ENERGY
2000

FUELLING ONTARIO'S FUTURE

Ontario
Ministry of Energy
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Minister

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Fuelling Ontario's Future

Foreword

The year 2000 is only 15 years away.

By the year 2000, it will have been 29 years since the start-up of the world's first commercial CANDU nuclear power station. It will have been almost 30 years since the Organization of Petroleum Exporting Countries shocked Canada and the rest of the world by quadrupling the price of their oil, and it will have been over 40 years since natural gas first flowed through the TransCanada pipeline system to Ontario.

Where will Ontario's supplies of energy come from? How will the people of Ontario use this energy?

These key questions are addressed in two papers produced by the Ministry of Energy. This paper, **Fuelling Ontario's Future**, looks at the first question. A companion paper, **The Shape of Ontario's Energy Demand**, looks at the second question.

The papers have been written to provide information and to stimulate discussion. Descriptions of alternative futures are presented — ranges of possible international energy prices, varying patterns of price changes, and differing levels of economic growth are described and their implications for energy demand are assessed. Against this background, supply options for Canada and Ontario are discussed. The papers highlight options and issues. As such, they do not end with a series of policy recommendations. These will result from wide discussions and from further examination of the issues and options for energy supply and demand to the year 2000.

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EXECUTIVE SUMMARY

Canada is likely to have an adequate supply of energy in the year 2000. Ontario, as a major consumer of energy resources, will enjoy the opportunity to choose among several supply options to satisfy its energy needs. In particular, a wide range of options is available to supply the growth in Ontario's electricity requirements. Some crude oil and natural gas supply options which may be available in the year 2000 are high-cost. Therefore, their development will be sensitive to energy price trends which remain uncertain. These are the primary conclusions of a study of Ontario's energy supplies undertaken by the Ministry of Energy.

Key Findings

Electricity

- No major breakthroughs are expected in electricity generation, storage, or transmission technologies. The bulk of Ontario's electricity is expected to be generated in 2000 by nuclear power.
- The potential to generate surplus electricity within the Province will continue well into the 1990s. However, decisions will be required before then about what additional programs and facilities may be needed by the late 1990s and in the post-2000 period. Major options for providing for Ontario's needs include: load management and conservation programs led by the utilities, refurbishment of existing plants, new hydraulic stations, nuclear power, electricity purchases from Quebec or Manitoba, new coal plants and alternative generation.

Crude Oil

- Should Canada wish to maintain its position as an exporter of oil, or to merely maintain its net supply self-sufficiency, it will need to have supplies from new sources by the early 1990s.
- Ontario will continue to remain dependent upon sources of crude oil which are outside the Province. It is expected that by 2000, a small but increasing proportion of Ontario's oil supply will be imported into the country.
- The development of high-cost crude oil supplies, such as frontier reserves and tar sands, will be very sensitive to price trends. Heavy crude oil upgrading will be a significant focus of activity between now and the year 2000.

Natural Gas

- With respect to natural gas, Ontario should have ample supplies of reasonably priced natural gas from conventional producing areas in western Canada through the year 2000.
- Once conventional supplies begin their decline, Ontario will enjoy several supply options. Large reserves have already been discovered in frontier areas. Natural gas could be available from the Beaufort Sea — Mackenzie Delta, the East Coast Offshore, the Deep Basin of west-central Alberta, and from the Arctic Islands.

Coal

- Coal will continue to play a major role as a feedstock and energy source in Ontario's steel industry. It will also continue to be burned for electricity production, but the quantity will depend on the choices made to supply future electricity needs.

Other Energy Sources

- New energy sources will continue to play a relatively minor role in Ontario's energy supplies to the year 2000 although industrial opportunities in selected market niches will continue to grow.

Two alternative scenarios have been developed by the Ministry, in addition to a Base Outlook, to reflect the uncertainty about international energy prices, economic growth rates and total energy demand. In particular, the development of the electricity system in Ontario is driven by electricity demand growth. Growth in total electricity sales in Ontario between 1984 and 2000 could be 60 per cent in the High Demand Outlook and 23 per cent in the Low Demand Outlook. The development of new oil and gas supplies, and of new energy sources, is driven more by price and price expectations. Alternative scenarios could see crude oil and wholesale natural gas prices some 25 per cent above or below the Base Outlook in 2000.

INTRODUCTION

Today, oil is the dominant energy source in the world and in Canada. Since the Arab oil embargo of 1973, the developed nations around the world have taken major steps to reduce the crude oil share of their energy supply, and much has been achieved. However, oil still represents 40 per cent of the world's annual energy use, 43 per cent of Canada's and 40 per cent of Ontario's. Natural gas, coal, nuclear power and hydraulic energy also make major contributions. Other less significant contributions are made by solar energy, wind, wood, energy from waste and a variety of other sources.

This major dependence on oil places Ontario in a vulnerable position, since its indigenous conventional crude oil resources are very limited. In Ontario over the past 15 years, nuclear power — an indigenous energy source — and natural gas from western Canada have played major roles in reducing crude oil demand. Further potential exists to substitute these energy sources for oil.

Over the next 15 years, natural gas and nuclear power are expected to continue to increase their share of energy markets. Several renewable energy sources also have the potential to replace oil in a variety of specific applications.

The pace of energy developments will be strongly influenced by both the extent of economic growth and the price of energy.

The Ministry has developed a number of scenarios which provide a background for assessing supply options in the year 2000. In the environment of the 1980s, no-one can forecast with any certainty — it is much more useful to consider a range of possibilities. The scenarios consist of assumptions about population growth and economic growth, the prices of crude oil, natural gas, and electricity as well as resulting energy demand growth rates.

In the Base Outlook for prices developed by the Ministry, world oil prices in the year 2000 are projected to be around \$34/barrel or \$5.60/gigajoule (official price of Arabian light crude oil in constant 1985 U.S. dollars). This is above the price in the summer of 1985 of \$28/barrel or \$4.60/gigajoule, but below the price in 1980 of \$41/barrel or \$6.70/gigajoule (in 1985 U.S. dollars). The Base Outlook for natural gas prices follows a similar pattern. A wholesale price of \$4.90 per Mcf or \$4.55 per gigajoule (in 1985 dollars) is projected for natural gas in Toronto in the year 2000, some 18 per cent above the 1985 price.

In the Base Outlook, total energy demand in Ontario is expected to grow at a rate of 1.1 per cent per year from 1984 to the year 2000. Provincial economic growth is projected to average 2.7 per cent over the same period.

In the alternative High Price Scenario, crude oil prices are projected to rise to \$43 U.S./barrel (\$7.00/gigajoule) in 2000, and natural gas prices are expected to reach \$6.00 per Mcf (\$5.60/gigajoule). With slow

economic growth, total energy demand is projected to grow at an average of only 0.2 per cent per year.

In the Low Price and High Demand Scenario, crude oil prices are projected to remain soft and be only $26.00 U.S./barrel ($4.25/gigajoule) in 2000, while natural gas prices are projected to be $3.65 per Mcf ($3.40/gigajoule). With these low prices and faster economic growth, total energy demand could grow at an average rate of 2.2 per cent per year in this Scenario.

Many factors which could not be captured in the scenarios could also be important. For example, the precipitousness of price rises, or price drops, could be as important as the amount of the price change itself. Sudden price changes often initiate different responses than smooth price changes.

This paper examines energy supply sources from a Canadian and an Ontario perspective. Discussion revolves around the supply options which exist, how these options may develop and the issues which must be faced. In discussing electricity and the new and emerging energy sources, detailed scenarios which focus on Ontario are used in presenting supply options. In discussing crude oil and natural gas, Ontario's requirements are only part of a broader national and international picture. The price and demand Scenarios and their projections for the use of electricity, crude oil, natural gas and other energy forms in the Province are described fully in the companion paper on energy demand entitled **The Shape of Ontario's Energy Demand**.

This paper, **Fuelling Ontario's Future**, focuses first on three major energy supply sectors: electricity, crude oil and natural gas. A separate section deals with other energy sources which do not fall naturally into these sectors. Each section begins by describing the global scene and moves to a narrower focus by outlining options for Canada and Ontario. Implications are then discussed. The major challenges and opportunities for Ontario are drawn together in the final section.

ELECTRICITY

Ontario is dependent on energy supplies from outside its borders for over two-thirds of the fuel used within the Province. Electricity provides one means of harnessing the major energy sources which do exist within the Province. It assumes a major role in any energy supply planning for Ontario.

World Trends

Given the range of international energy prices described in the Introduction, a number of developments can be postulated for the world-wide growth of electricity supply systems. These will have impacts on the development of Ontario's electricity supply system, albeit to differing extents.

It is likely that the industrialized countries, in the year 2000, will continue to have very strong grids dependent on centralized power production. These grids are likely to be supplemented by generation from privately-owned facilities.

Differences in how the various generation types, transmission systems, and storage systems evolve will be seen.

Nuclear Plants

Nuclear power has become increasingly important in Europe and North America since its introduction on a commercial basis in the 1960s. By the year 2000, it will form the backbone of the generation system in a number of European countries. Some experts predict that by 2000 over 50 per cent of the electricity in the European Economic Community could come from nuclear generation. The world's first commercial "breeder" reactor may well be operating, most probably in France, by the turn of the century.

However, the growth of nuclear power has not been as great as was expected 20 years ago, and current activity is not sufficient to maintain all of the existing nuclear construction industry. In futures with moderate rates of growth in the demand for energy, the nuclear industry all over the world is likely to undergo substantial change.

By the year 2000, several countries are likely to have dramatically reduced the size of their nuclear construction industries and consolidation of the international industry will have occurred.

While the role of nuclear power does not change dramatically by the year 2000 over a wide range of futures, the outlook for nuclear power beyond 2000 is uncertain. In futures involving high overall energy demand growth rates, the nuclear power station construction industry is likely to be very active and looking forward to significant future expansion, and, potentially, to plants using advanced fuel cycles.

In futures which see low crude oil prices, and where electricity does not displace large amounts of oil, or where overall energy demand growth rates are low, the nuclear construction industry is likely to be very weak.

Coal Plants

Coal-fired generation is now, and is likely to continue to be, the cheapest means of generating large amounts of electricity in those areas of the world where large coal deposits exist, and where mining and transportation costs are low, such as in the mid-western United States and in Alberta. In other systems, coal will play an intermediate role. Coal stations have lower capital costs than nuclear stations, but much higher fuel costs. The cost of electricity from coal-fired generating stations is likely to increase as more stringent acid gas control is required.

Coal-fired generation must compete economically with nuclear-powered generation. Therefore, although it can be used to replace oil-fired generation, the amount of coal used for utility electricity generation is not likely to change substantially as a direct result of changes in oil prices. An exception would be where refurbishments are required at oil-fired stations. These might be converted to coal-burning stations.

Oil and Natural Gas-Fired Plants

The use of oil and natural gas-fired generation is likely to continue until well after the year 2000. Gas-fired plants are common now in areas of the United States with substantial natural gas reserves or with access to cheap natural gas supplies. The use of natural gas for centralized electrical generation is likely to decrease as competition for available supplies becomes more intense. However, oil and gas-fired stations will continue to have an appeal because of their relatively low capital costs and, in the case of natural gas, because of the relatively slight environmental impact.

Cogeneration (the simultaneous production of electricity and useful heat) will be one area where the use of natural gas is likely to increase.

Cogeneration

In Europe, substantial amounts of private and utility cogeneration have existed for several decades. In Canada, cogeneration has played a secondary role, but has been used by the chemical and pulp and paper industries. In all but the very low energy price futures, it is likely that the contribution from cogeneration using coal and natural gas is likely to increase in the industrialized countries.

Definitions

Base Load Plant

A generating station which operates at full output over large portions of the year is referred to as a base load plant. The plants tend to be large generating units, for example nuclear, which have low operating costs.

Breeder Reactor

A type of reactor in which the amount of fissile material produced is greater than the amount of fissile material consumed is called a breeder reactor. Breeder reactors typically produce plutonium-239, while transforming uranium-238 and using plutonium-239 and uranium-235.

Centralized Plant

Large nuclear power stations such as the Pickering Nuclear Generating Station are centralized plants. Electricity is produced in large amounts at one location and then transmitted and distributed to customers substantial distances from the plant.

Cogeneration

The simultaneous production of electricity and useful heat for an industrial process is called cogeneration. It is a very efficient way to use fuel.

Conventional Power Plant

Conventional generating stations are those that are commercially available. In Ontario, they include coal, oil and natural gas-fired plants, as well as hydraulic and nuclear-powered facilities.

Once Through Fuel Cycle

A cycle of fuel use where uranium fuel is used in a nuclear reactor only once is called a once through fuel cycle. The fuel is not reprocessed.

Recycled Nuclear Fuel

Nuclear fuel (uranium, plutonium) which is extracted from spent fuel and reused in fresh fuel rods is termed recycled nuclear fuel.

Unconventional Power Plant

Windmills, photovoltaics, and fuel cells which are not currently in widespread use for electricity generation are called unconventional power plants.

Other Generation Types

Other generation plants such as wind-powered systems, photovoltaics and small hydro systems are all likely to be used in various market niches. Such sources are especially appealing in countries which currently lack centralized systems. National grids may develop starting from a number of small isolated grids. The use of such generation sources to displace oil-fired electricity plants would be accelerated in high crude oil price futures, or where regional energy security becomes a concern. Very little development is required for these technologies to be competitive in many parts of the world. Cost effectiveness is likely to improve as they become used more widely.

Transmission

Electricity transmission and distribution technologies will have undergone changes in a number of areas by the year 2000. Higher voltage lines (1000 kilovolts) will be more common than during the 1980s. Direct current transmission is also likely to be more common, especially in situations where generation sites are distant from load centres. While advances in superconducting transmission lines are possible, commercialization awaits major breakthroughs.

The planning and operation of generation probably will still be carried out to meet regional needs. In North America, regional inter-ties are expected to be relatively weak.

Strategic Conservation

Traditionally, electricity supply planning has involved planning changes to the generation, transmission and distribution system necessary to meet demand. The low price of energy, the rapidly growing economy and the changes in technology which made economies of scale increasingly attractive in the past led to a focus on supply. Increasingly, however, demand management and conservation options are being examined and programs are being selected so that the financial and technical resources available to the utility are used to minimize the cost of supplying the services that electricity provides. By 2000, demand management and strategic conservation are likely to be accepted parts of utility planning.

Storage

Electricity storage technologies are likely to remain expensive, but may be introduced on a significant scale in electricity systems lacking hydroelectric plants to meet their peak loads. Distributed batteries and fuel cells may prove to be the most cost-effective storage solutions in smaller electricity networks, or where distribution systems are weak. Large pumped storage stations will be used to complement nuclear power plants in large systems.

Decentralized Plant

Decentralized plants are small and serve local communities rather than large regions.

Demand Management

Demand management is the use of marketing or incentive programs, for example, to encourage demand growth or demand reduction to influence the overall level or characteristics of demand.

Parallel Generation

The generation of electricity from equipment which is interconnected to an electrical grid system, but which is neither owned nor operated by a utility is called parallel generation (examples are interconnected industrial co-generation and private hydroelectric generation).

Peak Load Plant

A generating station such as a coal or an oil-fired plant which provides electricity during periods of high electricity demand is considered a peak load plant. These plants are used less often than base load plants because of their high fuel costs. However, they are flexible in that they can be brought "on line" quickly or shut off as needed.

Plant Refurbishment

The replacement of major pieces of equipment in a generating station to extend the useful life of the plant is referred to as plant refurbishment.

Strategic Conservation

The use of utility resources to speed the penetration of more efficient equipment into major electricity-using processes within the Province is called strategic conservation.

ELECTRICITY

Options for Ontario's Electricity System

Ontario's electricity supply system is composed of the generation and transmission system — largely owned and operated by Ontario Hydro — and the distribution system. The system includes over 70 generating stations and over 100,000 kilometres of transmission circuits and distribution lines. Ontario Hydro works in partnership with over 320 hydroelectric and public utilities commissions. In 1984, electricity sales in Ontario exceeded 130 terawatthours (380 petajoules).

The name, Ontario Hydro, reflects the predominant generation type used by the corporation in the early years of its history. Hydraulic plants were used almost exclusively until coal-fired plants were introduced into the system in 1951. Nuclear power first made its appearance in the Ontario Hydro system in 1967. Currently, total electricity generation by Ontario Hydro is split roughly equally between hydraulic plants, coal plants and nuclear plants. Three nuclear stations are currently under construction and a number of coal and gas-fired stations are nearing the end of their designed life so that in the future, the Ontario Hydro system will increasingly rely on nuclear generation to minimize total system cost.

Ontario Hydro Major Generating Stations and Transmission Routes

Definitions

Energy Storage Systems

Energy is stored at various points throughout the energy production and utilization cycle. Raw or processed fuels are stored in, for example, coal piles or oil tanks before they are transported and distributed. Closer to the end use side, energy is stored in devices such as domestic hot water heaters and automobile gasoline tanks. Energy storage systems are generally classified as mechanical, thermal, chemical or electromagnetic. Several electrical storage systems are described below.

Pumped Storage

Pumped storage is a mechanical method of storing energy where off-peak power is used to pump water to a reservoir, above or underground. The water is then released during peak demand periods to generate electricity.

Compressed Air Storage

This involves the compression of air into underground caves or abandoned mine shafts during off-peak periods. The compressed air is released during peak demand to combust natural gas or light fuel oil in a gas turbine generating plant.

Fuel Cell Power Plants

Fuel cell power plants can be considered part of a storage system. Electricity is used to obtain hydrogen from water through hydrolysis. The energy stored in hydrogen fuel can later be converted back into electricity using a fuel cell power plant.

Battery Storage

Battery storage involves the conversion of electrical energy to chemical energy and the short term storage of this energy in sodium-sulphur, sodium chloride, lithium-metal-sulphide, zinc-chloride or redox batteries. Battery storage of energy could prove to be useful for transportation applications.

The companion paper on energy demand includes a number of scenarios or outlooks which describe possible energy demand growth in the Province to the year 2000. The outlooks are used to explore supply source and electricity generation options. Electricity prices, market shares and rates of economic and electricity demand growth for three Ministry scenarios are summarized below.

Scenarios*

	Base Outlook	High Demand Outlook	Low Demand Outlook
Growth Rates (1984 to 2000)			
Ontario's Economic Growth (% per year)	2.7	3.8	1.5
Electricity Demand Growth (% per year)	2.2	3.0	1.3
Residential Electricity Price in 2000**			
(1985 Cdn ¢/kWh)	4.7	4.4	5.0
(1985 $/GJ)	13.0	12.1	13.9
Electricity Market Share (%) in 2000	19.0	19.0	19.0

(Over the last 15-year period, electricity demand growth in Ontario has averaged 3.6% per annum. In 1984, the electricity market share in Ontario was 16%.)

* For details, see the companion paper, **The Shape of Ontario's Energy Demand** (Ministry of Energy, 1985).

** Based on the end block rate for a residential customer in a representative municipal utility.

The rates of growth estimated for each of the Ministry's scenarios represent major changes from growth rates experienced after the war years and up until the late 1960s. During that period, electricity sales increased by 7 per cent per annum and as a result, total sales doubled every 10 years. In the Ministry's Base Outlook, total electricity sales in the year 2000 are expected to have increased by 40 per cent over sales in 1984. The reduced growth rates result from decreased rates of economic growth, increased end-use efficiency, and market saturation in several key market areas.

A consequence of the slowed demand growth and an ongoing construction program is large surpluses of generating capacity over the medium-term.

Over the longer-term, new plants will again be required.

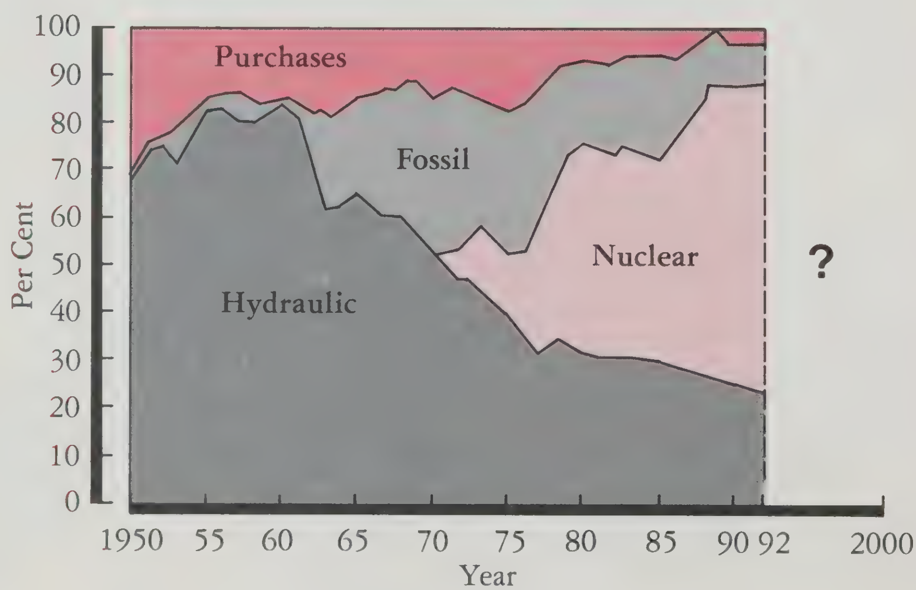
Ontario Hydro has recently completed or has under construction over 8,000 megawatts of generating capacity. This amount is equivalent to more than 4 times Ontario Hydro's installed capacity at Niagara Falls and along the Niagara River. The last unit of this committed construction program is scheduled to come into service in 1992.

In the Base Outlook, almost 3,000 megawatts of additional uncommitted generation, equivalent demand management or a combination of these is required before 2000. The exact figure depends on assumptions about the future load factor of demand, retirement of aging plants, the need for reserve capacity and future performance of existing plants.

The Ministry's High Demand Scenario would call for over 7,000 megawatts of new capacity or demand management by the year 2000. In the Low Demand Scenario, no new uncommitted capacity or programs would be needed until well after 2000.

Since each of these outlooks seems credible, it follows that planning the optimal development of the system will be challenging. Ontario is fortunate to have a variety of options for adapting the system to meet the changing need for electricity. Ontario can choose from among a variety of conventional generation technologies, alternative generation technologies and electricity purchases. It can use a variety of possibilities for strategic conservation and demand management, or it can defer decisions by reducing target reserve margins.

Ontario Hydro's Supply Mix (1950-2000)



Conventional Generating Stations

Conventional generating stations are those that are commercially available. In Ontario, they include coal, oil, and natural gas-fired plants as well as hydraulic and nuclear powered facilities.

Hydroelectric Stations

There remain some 9,000 megawatts of undeveloped peak hydroelectric capacity in Ontario.

Summary of Ontario's Hydroelectric Resources (1985)

Existing Stations	Number of Stations	Installed Capacity (MW)	Average Output (MW)
Ontario Hydro	68	6,530	4,040
Private	100 (approx.)	670	410
Total		7,200	4,450
Undeveloped Resources			
Redevelopments	2	150*	75*
Plant Extensions	20	2,000*	275*
Remote Northern Rivers	10	3,850	1,300
New Sites — over 10 MW	36	2,600	1,000
Small Hydro — under 10 MW	300	500	350
Total		9,100	3,000
Pumped storage	10	4,800 (approx.)	negative**

* Increased capacity
** Pumped storage schemes do not produce additional energy, they store energy during periods when excess energy is available and release it during periods of high demand.

Studies are currently underway to clarify the costs of development on the Little Jackfish and Mattagami Rivers, and of further development on the Niagara River.

Hydraulic developments are attractive because they use a renewable and indigenous resource. They also offer long life and potentially low cost. However, not all of the resource can be tapped. More than a third of this undeveloped capacity exists in remote areas. Development at many sites could be disruptive, both environmentally and socially. For remote areas, costs at the site and for required transmission will be high.

Coal-Fired Generation

Currently, some 10,000 megawatts of coal-fired plants exist in the system. Coal plants are used only at times of high demand when the available lower-fuel-cost plants are already being used. As a result, annual capacity factors are currently 35 per cent rather than 70 per cent, which these plants are capable of, if they are needed. One option for meeting increased electricity needs would be to increase the capacity factor of available plants and to refurbish existing stations to extend their life.

At present, increased use of coal-fired generation leads to increased production of acid gas. However, technical options such as "scrubbers", L.I.M.B. technology (limestone injection in multi-stage burners), fluidized bed combustion, and slagging burners are currently being investigated and may provide a cost-effective means of reducing acid gas emissions.

Coal provides the current system with the most cost-effective means of maintaining generation flexibility and fuel diversity. However, current cost estimates suggest that over the life of each plant type, new coal plants may not compete economically with new base-loaded nuclear plants. On the other hand, it may be desirable to maintain a certain level of coal use to prevent deterioration of the coal supply infrastructure and to maintain flexibility.

Ontario's coal currently comes from western Canada and the north-eastern United States. A desire for greater use of Canadian resources might lead to the use of more coal from the Canadian west or the Canadian east coast. Purchase costs would be higher and technical difficulties involving boiler design limitations would have to be overcome. Ontario does have coal (lignite) deposits, but they are of low quality and are currently uneconomical to use.

Nuclear Generation

The CANDU design of nuclear reactors provides Ontario with a technology capable of producing large amounts of electricity safely, dependably, and cost-effectively. Ontario also has large reserves of uranium which can be processed to provide fuel for these stations. Building new nuclear stations would be one option for meeting increased electricity demands, and for making greater use of indigenous resources.

The current generation of nuclear power employs a "once through" fuel cycle. If energy costs rise substantially or demand grows rapidly, the technology may evolve into more advanced systems using other fuels and "recycled" fuels. Advanced fuel cycles hold great promise, since they magnify the energy potentially available from nuclear fuels by a factor of over 50.

Coal Technology: Definitions

Scrubbers

A device for reducing the emission of sulphur dioxide and particulate matter from the exhaust gases of power station boilers by injection of an aqueous slurry containing an active material such as limestone.

L.I.M.B.

Limestone Injection in Multi-Stage Burners — A technology for injecting limestone into the boiler above burners in order to reduce sulphur dioxide emissions. This system also reduces nitrogen oxide emissions.

Fluidized Bed Combustion

A technology for burning a wide range of solid fuels in a bed of limestone or oil shale in order to produce heat in a more efficient manner than the normal pulverised coal systems, resulting in reduced acid gas emissions.

Slagging Burner

A technology for controlling sulphur dioxide and nitrogen oxides from coal-fired boilers using a high temperature pre-combustion cylinder mounted on the front of the boiler. The ash melts and runs out of the cylinder in a fused form for easy disposal.

The nuclear option is not without its difficulties, however. When system expansion occurs more slowly to meet forecasts of lower electricity demand growth, nuclear power may be more difficult to build cost-effectively. Nuclear stations have taken advantage of economies of scale to counter escalation in station costs. In the past, the nuclear industry was large enough to ensure efficient use of the technological expertise required and to guarantee high utilization rates for the specialized equipment needed in station construction. Unless reactor export sales increase to balance lower domestic requirements, sustaining an industry capable of building these stations will be difficult and the cost of future stations may be higher.

Radioactive waste disposal has been a much debated concern and a wide range of options have been considered. It is now recognized that it is possible to retain the high-level radioactive waste in accessible cooling ponds for a 50 year period after their extraction from the reactor. Both reprocessing of waste or permanent disposal therefore remain as options. Decisions about which path Ontario will follow will not be required for many years, though it may remain as an issue if new nuclear stations are being planned.

Oil and Natural Gas Burning

Stations fueled by oil and natural gas have been used in the past in the Ontario Hydro system. A total of over 3,000 megawatts currently exists in the system in a mothballed state — this plant could be brought to active service in less than a year if needed.

The current cost of these fuels and the expectation of continuing high prices suggest that these stations, if activated again, would be used only in a limited role. If financial or other constraints limit the use of coal or nuclear plants, this capacity may be used more extensively.

Alternative Generation

Alternative Generation is defined as electrical generation within the Province undertaken by some entity other than Ontario Hydro, as well as any non-conventional generation, even if undertaken by Ontario Hydro. With many alternative generation technologies, the economics are dominated by site-specific conditions. For some, low-cost fuels exist as by-products, or as waste from other processes at the site. With technologies which utilize renewable energy sources such as river flows, or the wind, the economics may be made more attractive because of the particular circumstances or characteristics of the companies involved (i.e., the ability to raise capital cheaply, or to absorb maintenance costs).

Factors of prime importance affecting the amount of alternative generation which develops in the Province are the price of electricity relative to the cost of various fuels and "buy-back" rates — the rates offered by the utility for the purchase of electricity.

Cogeneration

Cogeneration could, in principle, provide a major contribution to the electricity supplies of the Province.

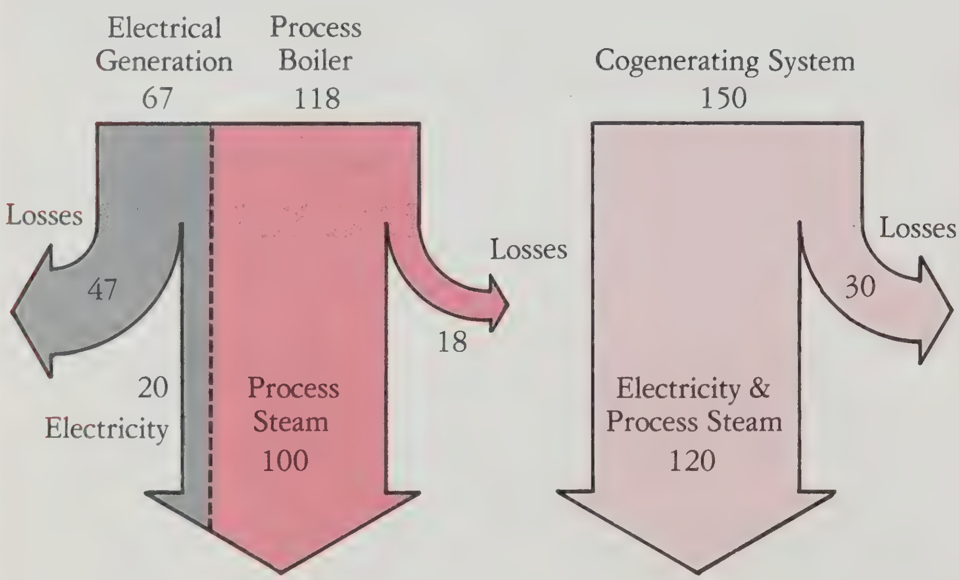
The efficiency of fuel use in cogeneration is very high — in some cases, it can exceed 80 per cent. Costs can also be high because, relative to the size of plant which Ontario Hydro uses in central stations, the electricity generation units are small. To reduce fuel handling costs and environmental impact, generally only high-quality fuels such as oil or natural gas are used.

Currently, over 500 megawatts of industrial cogeneration exists in Ontario. It has been estimated that by the year 2000, a technical potential of over 5,000 megawatts for cogeneration could exist in Ontario using the type of technologies currently in use. The economic potential is lower. In the Ministry's Base Outlook, it is assumed that an additional 300 megawatts of cogeneration capacity will be added to the system by the year 2000.

Energy Savings from Cogeneration

Utility Generation & Process Boiler

Cogeneration



Financing availability and the requirements of environmental legislation will both affect the extent to which industry takes advantage of cogeneration opportunities. The possibilities for the increased use of coal through technologies such as fluidized bed combustion or through coal preprocessing (using powdered coal and coal-water mixtures) are important for the greater development of cogeneration. Use of cheaper fuels makes cogeneration opportunities more economic.

Cogeneration — What and Why

Industries in Ontario, particularly the chemical and pulp and paper industries, require large amounts of steam for their processes. If this steam is produced at a higher temperature and pressure than is needed by the process, it can be passed through a steam turbine to produce electricity. The steam exiting the turbine is then used in the process. This is the most common approach to cogeneration across Canada.

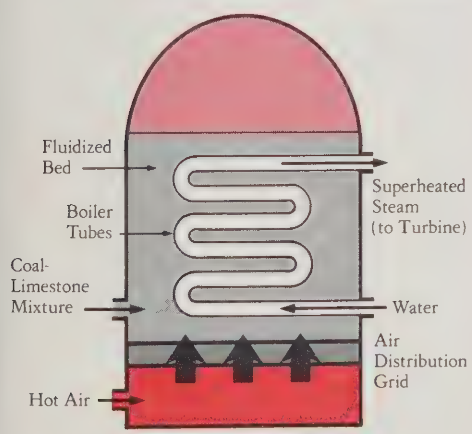
The other major method of cogeneration is the production of electricity by running a gas turbine and using the hot exhaust from the turbine to produce steam.

The fuel savings from cogeneration can be seen in the diagrams which follow. In both figures, 120 units of useful energy are produced. If cogeneration is utilized, only 150 energy units are required with an overall efficiency of 80 per cent to generate both electricity and process steam. By comparison, conventional utility electrical generation (30 per cent efficient) and a standard boiler producing steam (85 per cent efficient) require a total of 185 energy units. The fuel savings using cogeneration in this example represent 19 per cent of input fuel.

What Is Fluidized Bed Combustion?

Fluidized bed combustion (FBC) allows low-grade and high sulphur coals to be burned while restricting the emission of sulphur gases to the atmosphere. The diagram shows an FBC boiler where coal is burned, producing steam to drive the turbines. A mixture of crushed limestone, coal and hot gas (air) composes the fluidized bed surrounding the boiler tubes, which provides an equal distribution of heat. The limestone particles remove the undesirable gases by reacting chemically with the sulphur oxides to form calcium sulphate, which is then left behind as solid waste.

A Fluidized Bed Combustion Boiler



Other fuels could also be used for cogeneration. The forest products industry presents a major opportunity in Ontario. Large amounts of wood waste are available on site and are burned to provide steam and hot water for process requirements. Modifications are possible to include electrical generation. A large mill in Chapleau recently announced its intention to install one such cogeneration scheme.

Municipal solid waste is another fuel that can be used for cogeneration. The use of municipal waste as a source of energy is discussed later in this paper.

Fluidized Bed Combustion

Fluidized bed combustion (FBC) technologies make use of a burner where air or a mixture of gases is blown up through a bed of granular material to improve combustion characteristics. In the case of coal combustion, the bed material is usually limestone, with the fuel comprising about 5 per cent of the bed. Techniques for using oil shales are being developed. Fluidized bed combustion uses a much lower combustion temperature resulting in lower nitrogen oxides and sulphur dioxide emissions. Fluidized bed combustion also can be used to burn materials such as wood waste or municipal garbage.

Unit sizes of up to 160 megawatts are being built on a commercial scale in the United States, and 500 megawatt units are planned. The reliability and economics have yet to be proven for the large unit sizes.

Wind

In theory, windpower could be used to generate all of the electricity required by the Province. Though Ontario is not a windy area, the wind "resource" is huge. The difficulty is that the economic viability of using windpower depends very much upon the wind speeds at the site. All else being equal, harnessing windpower in areas such as central Ontario (where average windspeeds are 4.5 metres per second) would cost twice as much as in areas such as Denmark where annual average windspeeds are closer to 5.5 metres per second.

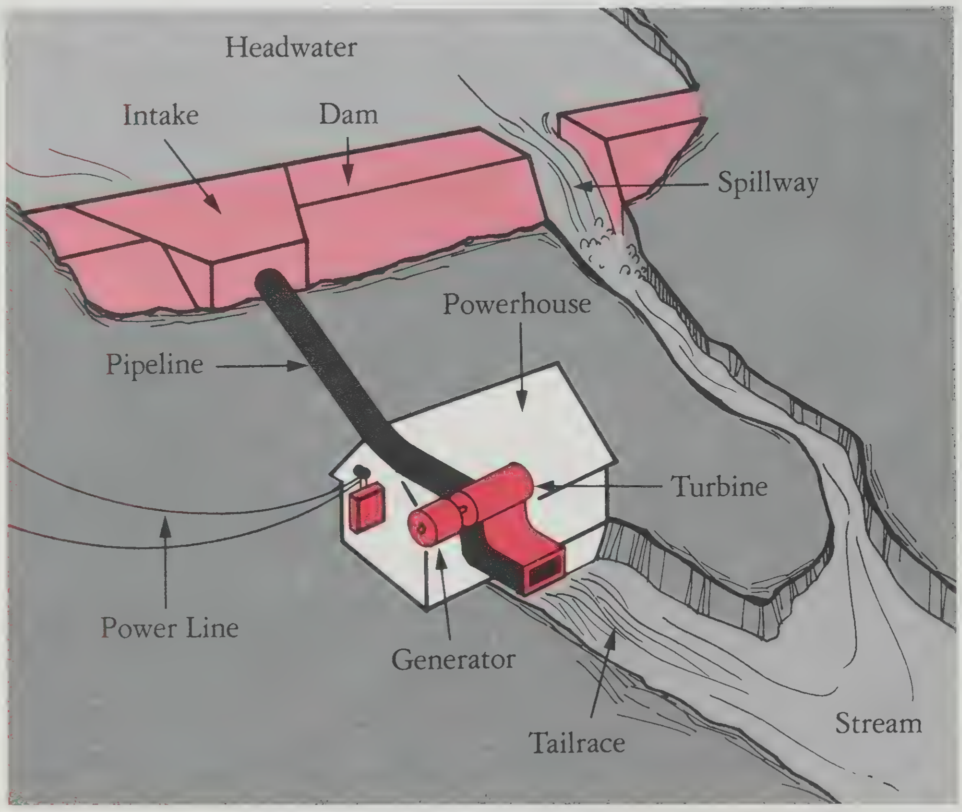
There are additional hurdles which the large-scale use of windpower would face. These include the intermittent nature of wind which requires that a certain amount of back-up generation be available. More importantly, the uncertainty surrounding the environmental acceptability of the structures themselves remains an obstacle.

Nevertheless, wind power may play a role in future power generation even if only on a small scale in Ontario, and primarily in locations remote from the electric grid.

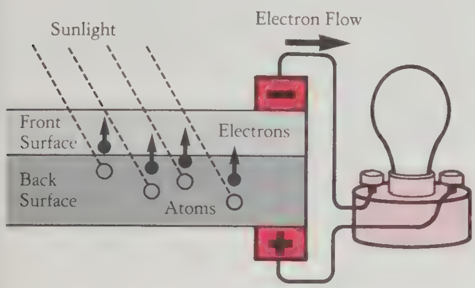
Small Hydro

Small hydroelectric plants provide a nearer term option for increased parallel generation. Approximately 600 megawatts of private small hydro is already installed. The development of sites with dams is actively promoted by the Ontario Government, and the goal for 1995 is to add 100 megawatts of new small hydro. Small hydro refers to hydroelectric developments with a capacity of less than 10 megawatts. The amount of power that can be developed at each site depends on the head and flow available. The total untapped potential using sites with existing dams is approximately 500 megawatts.

A Typical Small Hydro Site



A Photovoltaic Cell



Purchase and Sales: Statistics

In 1983, Ontario Hydro exported 11.9 billion kilowatt hours (42.8 PJ) to utilities mostly in New York, Michigan and Vermont. These sales resulted in $160 million in income. Electricity purchases from utilities amounted to 5.8 billion kWh (20.9 PJ) at a cost of $96 million. By purchasing power rather than burning coal at Ontario power stations, additional net savings of $20 million were realized.

Ontario Hydro sold slightly less electricity, 10.6 billion kWh (38.1 PJ), to the U.S. in 1984, although the income increased to $164 million. Purchases were in the order of 8.2 billion kWh (29.5 PJ) at a cost of $127 million and represented fuel savings of $25 million.

Solar

Solar power can be used to produce electricity directly using photovoltaic cells. At the moment, photovoltaics can be economic in providing electricity in areas that are distant from the provincial electrical grid. Many navigation buoys and radio repeater stations currently are powered by photovoltaic systems. Providing electricity economically to larger remote loads such as isolated communities or telecommunication sites may be possible before the year 2000. Large grid-connected arrays like those being developed in southern California are unlikely to be economic in Ontario for many years. However, there may be opportunities to utilize Ontario's acknowledged strength in the electrical power industry to tap the growing international market for photovoltaics.

Appendix A provides more details on small hydro, photovoltaics and windpower.

Electricity Purchases

North America operates a coordinated system so that substantial amounts of power regularly flow across the boundaries of individual utilities. A number of utilities have special opportunities to increase their generation beyond that required by their own customers. Hydro Quebec and Manitoba Hydro both provide good examples of this.

Ontario Hydro could, in the future, take advantage of these opportunities more than it does at present. A variety of options exist to harness remaining hydraulic potential in Quebec and Manitoba. Participation by other utilities, either through agreement on long-term contracts or with pooled capital, could benefit all the utilities involved. **Benefits to Ontario of purchasing power include lower financial risk and more flexible scheduling of new plants into the grid. On the other hand, such arrangements export employment opportunities and reduce Ontario's control over its power requirements.**

Strategic Conservation

Demand side options that reduce the need for electricity may have shorter lead times than supply side options such as the construction of conventional plants. It may be that the need for system expansion can be avoided by strategic conservation — the use of utility resources to speed the penetration of more efficient capital stock into the major electricity-using processes within the Province. Thus, these options are of considerable interest.

Programs that have been successful in the United States include rebates to customers for insulating electrically-heated homes, incentives — paid for by the utility — to install more efficient lighting, and low-cost loans to industry to increase the efficiency of electrical motors. In Ontario, where electricity prices are lower, it may be difficult to estimate the impact of similar programs, and thus to evaluate demand side options against more traditional options.

Reduced Reserve Margins

If demand growth is higher than expected, the target reserve margins which affect the reliability of the electricity system may be reduced. In Ontario, if the average growth rate for electricity demand were to follow the High Demand Outlook of 3.0 per cent over a 10-year period, this might lead to occasional electricity interruptions by 1995 unless power could be purchased during key periods from neighbouring utilities or other measures could be taken. Supply responses to changes in growth are very slow because of the long lead times (due to environmental and other regulatory approvals) and long construction programs required for large plants. Reduced system reliability and greater dependence on neighboring utilities may be one option to reduce system costs and to defer decisions about supply options.

Discussion

Predictions of reduced demand growth rates for electricity demand and the uncertainty about the future have major implications for the electricity supply industry.

A Mix of Options

The desirability of expanding the system using conventional generation options is being questioned. Many analysts are calling for the increased use of a mix of program options to match supply and demand. It is argued that demand side options — projects aimed at increasing the efficiency with which energy is used — should be utilized as well as supply side options, and that more effective use should be made of existing plants by extending plant life through major refurbishment projects.

Choosing a "basket" of options will increase flexibility and reduce the risk of incurring unnecessary costs in meeting demand. Ideally, there should be a mix of plant types — undue dependence on a single generation type should be avoided — as well as a mix of centralized and decentralized plants.

Demand Side Options

The following options aim to reduce demand for energy through conservation and energy management strategies:

Conservation

- programs for insulating buildings
- rebates for the installation of efficient lights, motors, refrigerators, etc.

Peak Clipping

- consumers allow utility to turn off water heaters during certain times
- increase the number of interruptible power contracts which give the utility the right to interrupt electricity for agreed-upon lengths of time

Load Shifting

- lower rates for off-peak electricity use

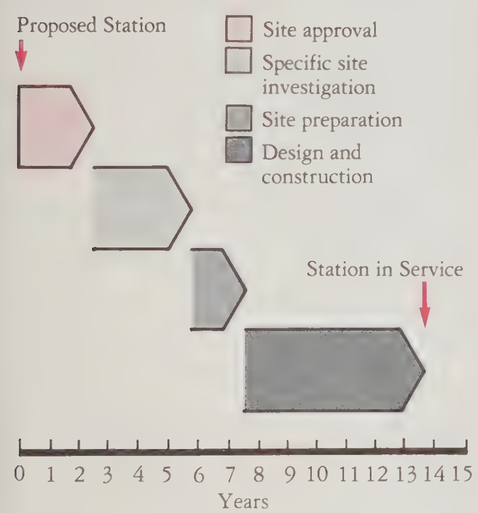
Strategic Load Growth

- incentive rates
- electric space heating
- development of electro-technologies for industrial use

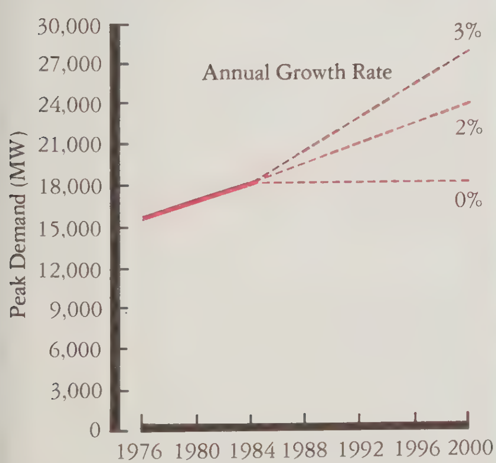
Long Lead Times

The lead time for the completion of an electric power generation station is up to 14 years from the initial site proposal. This allows time for legislative approval, public participation starting in the planning and design stages, and final construction (Figure 1). With such a long lead time, decisions regarding generation plants are often made in the midst of uncertainty regarding future electricity demand (Figure 2).

Generating Station Lead Times



Electricity Demand



The planning lead time for new stations is uncertain, and could be in excess of 14 years. Large centralized power stations to date have not been subjected to the full environmental assessment process. If small stations, developed either by the utility or the private sector, can be located and built in shorter time periods, they may be the preferred option. Small stations may offer the advantage of requiring fewer major transmission lines.

Such stations would have lower financial risk associated with them and they would be more amenable to development by small institutions and private companies. The existing electricity equipment supply industry easily could provide equipment for these smaller projects. Equally, demand side options, as with smaller stations, may have shorter lead times.

New Markets for Electricity

If, however, demand growth were to increase to rates such as 3 per cent or higher, it may be desirable to retain the current capability of building large centralized plants, and of returning to major construction programs such as those witnessed in the 1970s. One option over the medium term for maintaining industry capability and efficient use of facilities is to take advantage of slower demand growth rates by seeking new markets for electricity through increased electricity exports and by capturing greater shares of the domestic energy market.

Electricity Exports

If the Province continues the construction of new nuclear plants, it may be able to take advantage of the electricity export opportunities that arise from their low fuelling cost. The export option is appealing since it may be one way to ensure security of supply during periods of uncertainty about load growth trends; to moderate electricity rates in the Province; and to maintain the viability of the current generation construction industry. This option also has the appeal of assisting regional development during times of low economic growth. The risks that arise stem from the uncertainty about future markets and the extent of competition from neighbouring utilities and thus the potential of suffering major, unnecessary costs.

New Domestic Electricity Markets

It may also be possible to increase electricity's share of the provincial energy supply mix by entering key markets to displace the use of crude oil and natural gas. This has the advantage of increasing Ontario's control over its energy destiny as well as reducing the flow of jobs to outside the Province. On the other hand, seeking new markets too aggressively when the cost of competing energy sources could fall, may lead to the uneconomic allocation of provincial resources.

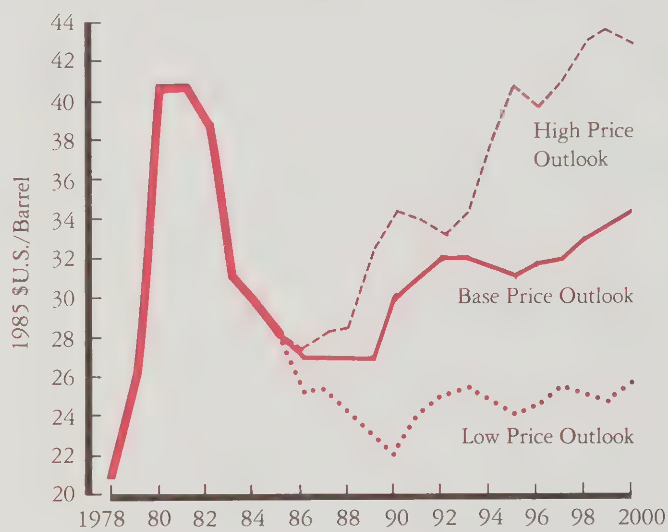
The challenges for Ontario are to maintain adequate supplies of low-cost electricity, while retaining enough flexibility to adapt to possible surprises in a very uncertain future. A commitment to a nuclear station in the next few years could only be made with the knowledge that it may inhibit development of Ontario's other generation options. Conversely, deferral of a decision about a new station may lead to a further weakening of Canada's nuclear industry and the loss of Ontario's ability to build such a station cost-effectively in the future.

CRUDE OIL

Today, crude oil supplies 40 per cent of Ontario's energy needs. The crude oil share is projected to decline to perhaps 32 per cent by 2000. Heating uses will largely be replaced by natural gas, electricity and other energy forms. By the year 2000, oil will be primarily used for transportation, petrochemicals and specialized uses, such as lubricants. The total demand for oil in Ontario is expected, in the Ministry's Base Outlook, to fall slightly over the next 15 years.

Ontario produces only a small amount of crude oil. Most of its supplies are obtained from Western Canada, although some supplies also come from overseas.

World Oil Price
(Official Price of Arabian Light)



Global Supplies

The world's supply of crude oil comes from many diverse sources. The major known accumulations, however, are not evenly distributed around the globe; rather, they are concentrated in a few areas. The greatest accumulations of known crude oil reserves have been found in the countries adjoining the Persian Gulf — the Middle East. This small region, about 5 ten-thousandths of the earth's surface, contains over 55 per cent of the world's proven reserves of conventional crude oil. Except for the Sultanate of Oman, these Persian Gulf countries are all members of the Organization of Petroleum Exporting Countries (OPEC). Furthermore, over three quarters of the world's known crude oil is found in only ten countries.

Major Known Conventional Oil Reserves

	Billions of Barrels	Exajoules
Saudi Arabia	169*	1,030
Kuwait	90*	550
U.S.S.R.	63	380
Iran	49*	300
United Arab Emirates	32*	190
U.S.	27	160
Venezuela	26*	160
Libya	21*	130
China	19	120
Total	496	3,020
Canada**	7	40
World Total	699	4,264

* OPEC members
** Not included in total; for reference purposes only.

Crude oil production, too, is not evenly distributed around the globe; but here, the variations are quite different. At 1984 production rates, the world's presently known crude oil reserves would last for 34 years. For OPEC, however, this period is 77 years, and for the Persian Gulf, an astounding 103 years.

Reserves-to-Production Ratios

(Presently Known Conventional Reserves)

	Years
Saudi Arabia	104
Kuwait	338
U.S.S.R.	14
Iran	61
Iraq	101
United Arab Emirates	81
U.S.	9
Venezuela	42
Libya	54
China	24
Canada	14
Total World	34

This "reserves-to-production ratio" for the 10 countries with the greatest reserves ranges from over 300 years for Kuwait, to 9 years for the United States.

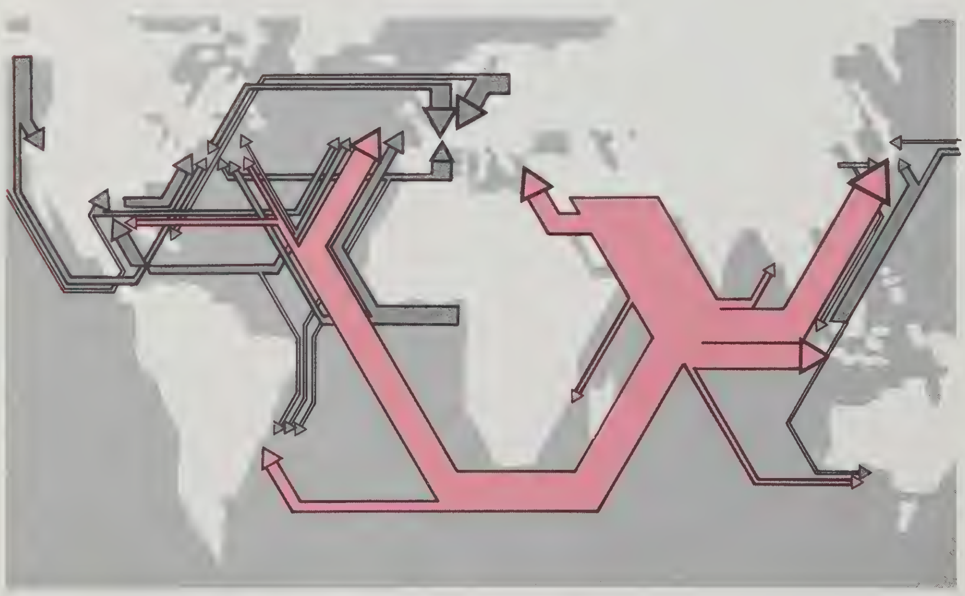
Over the next fifteen years, known crude oil reserves will be augmented by many new discoveries arising from on-going exploration efforts around the world.

The rate at which new reserves are found will depend upon the intensity of exploration efforts and the size of the resulting discoveries. The intensity of exploration will be governed largely by expectations of future crude oil prices and thus cannot be predicted with assurance. What is known, however, is that the average size of new discoveries is steadily declining. This trend towards smaller finds will almost certainly continue in the future.

When we recognize that the Persian Gulf still has the potential to yield major new crude oil discoveries, the importance of this small region, and of OPEC in general, to the world's future energy needs is readily apparent.

Other crude oil sources exist. However, they all have one common feature — they will all bear a much higher production cost than reserves in the Persian Gulf.

World Oil Flows



From BP Statistical Review of World Energy, June 1984.

Currently, the "hot spots" where important new conventional production is expected include Colombia and offshore Brazil, the northern reaches of the North Sea, Canada's Arctic and eastern coastal waters, China and perhaps the West African coast. While important for the future, none of these areas appear to have the potential to rival the Middle East.

The ultimate potential of the U.S.S.R. and China is only poorly understood in the West. Judging from performance in recent years and recognizing the harsh environment prevailing in its newer petroleum provinces, the U.S.S.R. will be hard-pressed to maintain its current production rate. A slow, gradual decline is considered probable. The potential of China, too, is not well known, but increased production there will probably be absorbed within its expanding economy.

Existing well-known techniques for producing conventional crude oil usually recover only about one-third of the oil in place in the reservoirs. New technologies (collectively referred to as "enhanced" or "tertiary" recovery) are being developed and put in place. Tertiary recovery methods hold promise for doubling the ultimate recovery of oil from these reservoirs. New recovery technologies will also add to the known reserves shown in the previous tables.

There are other forms of crude oil, sometimes called unconventional, which will take on increasing importance in the years ahead. The very heavy, bituminous oil in Northern Alberta and in Venezuela's Orinoco Oil Belt together contain three times as much petroleum as the total known conventional crude oil reserves of the world.

In addition to this vast resource, there are massive deposits of oil shales. In the U.S. alone, oil shales are estimated to contain perhaps 4 trillion barrels (24,000 exajoules) of oil equivalent, or about 200 years' supply for the world at the consumption rates experienced in 1984. While offering tremendous potential, these sources also bear a high cost burden.

The world is not running out of oil! It is, however, gradually drawing down to its reserves of low-cost oil.

The degree to which dependence on the Middle East grows is largely a function of the rate at which new sources of both conventional and non-conventional oil are developed. This rate, in turn, is a function of the price/cost relationship which is expected to prevail. An expectation of steadily rising prices will lead to fairly rapid development of new supply sources. Increasing prices also suppress demand through, for example, fuel switching and conservation, and this will eventually depress the price curve. Conversely, the expectation of flat or declining prices will result in a much slower development of new supply, perhaps some stimulation of demand, followed by a reversal into a rising price cycle as supply becomes limited.

If actual crude oil prices track or fall below the Base Price case it

What is Enhanced Oil Recovery?

When a petroleum oil reservoir is tapped, not all of the potential oil supply it contains is readily recoverable. On average, only about 30 per cent of the oil in place can be recovered with the natural energy of the reservoir moving the oil to the surface through the well. This is known as "primary" recovery.

In order to recover more oil from the reservoir, "secondary" recovery methods are often used. Techniques such as waterflooding and gas injection input additional energy into the reservoir, replacing the pressure available in primary recovery, to force more oil out of the reservoir.

Even with these techniques, much oil remains in the reservoir. Therefore, new techniques such as steam injection, in-situ combustion, carbon dioxide flooding, hydrocarbon miscible flooding and chemical flooding are being used to further enhance the recovery of remaining oil. These enhanced recovery methods are often referred to as "tertiary" or "third generation" oil recovery techniques.

What are Heavy and Light Crude Oils?

Crude oils are compounds of hydrogen and carbon with varying amounts of organic sulphur, nitrogen and oxygen content. The ratio of hydrogen and carbon molecules and the level of sulphur content determine different types or grades of crude oil.

Light crude oils usually have high hydrogen-to-carbon ratios, are commonly low in sulphur content, and generally flow freely at atmospheric temperatures. This means that light crude oils are relatively easy to produce and refine. Light crude oils currently contribute the bulk of domestic crude oil production in Canada.

Heavy crude oils on the other hand are generally characterized by lower hydrogen-to-carbon ratios and higher sulphur content, creating very dark, thick and often sticky viscous oils. Because of the high viscosity of many heavy crude oils, they do not "flow" as light crudes do with conventional recovery methods, and are more difficult to refine.

is likely that, given the differences in reserves-to-production ratios described earlier, the world will become increasingly dependent over the next 15 to 20 years on OPEC in general, and the Middle East in particular, for its crude oil supply.

If the High Price Case prevails, dependence on OPEC and the Middle East will be significantly less.

Canadian Supplies

Since the world's first crude oil well was brought in at Oil Springs, Ontario, 127 years ago, Canada has swung back and forth between being an oil exporter and an oil importer. Today, Canada is again a net exporter, although because of both constraints in Canada's internal oil transportation system and to minimize costs, Eastern Canada imports substantial quantities of foreign crude oil.

Western Canada Sedimentary Basin

Almost all of our domestic crude oil supply now comes from the Western Canada Sedimentary Basin, extending from Southwestern Manitoba to Northeastern British Columbia and the Northwest Territories. While this region will continue to yield significant new discoveries, recoverable reserves and productive capacity (particularly of the lighter, more valuable grades of crude oil) will almost certainly continue to decline.

Canadian Crude Oil Reserves

Canadian Crude Oil Reserves

Region	Established/ Discovered Reserves		Potential Undiscovered Reserves	
	barrels (billions)	EJ	barrels (billions)	EJ
Western Canada Basin*	4.5	27.5	3.7	22.6
Mackenzie Delta/Beaufort	0.7	4.3	8.5	51.9
Arctic Islands	0.5	3.0	4.3	26.2
East Coast Offshore	1.4	8.5	11.8	72.0
Other Areas	—	—	1.4	8.5
Totals	7.1	43.3	29.7	181.2

* Cumulative production to 1984 was 13.9 billion barrels (85 exajoules).
Source: Geological Survey of Canada, 1983

New reserves in the Western Canada Basin will probably be divided equally between new discoveries, extensions, and from enhanced recovery projects. Since the average size of new pool discoveries is gradually diminishing, and since the production response in enhanced recovery projects builds fairly slowly, new productive capacity from reserves additions will probably not be sufficient to replace the reserves decline in older fields.

To maintain its position as an exporter, or merely to maintain net supply self-sufficiency, Canada will need to have supplies from new sources by the early 1990s.

Beaufort Sea — Mackenzie Delta

Several potentially commercial oil discoveries have been made in the Beaufort Sea — Mackenzie Delta area. West Atkinson, West Tuk, Nipterk, Adgo, Issungnak, Amauligak and Tarsiut are among the largest to date. It is hoped that the 1985 drilling season will delineate sufficient reserves that planning of production and transportation systems can begin.

Design, construction and operation of these systems will pose formidable engineering challenges. Offshore installations will have to deal with enormous forces from floating ice-packs as well as protection of pipelines from ice scour in shallow water. Land installations, too, must overcome problems of muskeg and permafrost. All of these activities will take place in an environment where the winter weather can be harsh and all must be designed to protect a very fragile environment. The onshore and shallow water fields will most likely be connected either to the Norman Wells — Alberta pipeline or by a new line directly to Northern Alberta. With reasonable success and no sharp price drop in the next 2-3 years, crude oil should be flowing south by about 1990 to 1992.

The Geological Survey of Canada estimated discovered reserves at the end of 1983 to be in the order of 737 million barrels (4.5 exajoules).

Arctic Islands

To date, the Arctic Islands have yielded more natural gas than crude oil discoveries. Nevertheless, oil finds such as Cisco, Skate, Bent Horn and Cape MacMillan may prove to be commercial, particularly in the High Price Case, with innovative production and transportation facilities. The most probable transport will be by ice-strengthened tankers to the east coast. Under the Base Price Case, oil will not likely be produced in significant quantities from this area until perhaps the turn of the century.

Current estimates of discovered crude oil resources are 478 million barrels (1.8 exajoules).

East Coast Offshore

Much of Canada's east coast offshore appears to be natural gas-prone, with the exception of the Grand Banks area east of Newfoundland. The major crude oil discovery at Hibernia in 1979 has been followed by large strikes at Terra Nova, Ben Nevis, West Ben Nevis, Hebron, Nautilus and South Tempest. Hibernia is the only one of these discoveries which has been sufficiently delineated to permit production planning to begin.

Two types of production systems were considered for Hibernia, each with its distinct advantages and drawbacks. The first approach would use one or two floating platforms for development drilling and production facilities. The second would use a massive concrete structure resting directly on the ocean floor.

The major factors bearing on the choice of system are the complex geology of the area, the need to protect against the menace of huge icebergs drifting south from Davis Strait, and the extent of industrial benefits which Newfoundland will derive from construction and operation.

The Hibernia field contains two major reservoirs. Considerable faulting has occurred in the rock strata. Since the geology is complex, the best location for production facilities cannot be determined with certainty until much development drilling has been done.

The fixed platform would be a partially hollow concrete structure set on the ocean floor. The inner space would be used to store produced oil for shipping. In place, this structure would weigh over a million tonnes. Crude oil will be moved to market by shuttle tankers. Based on detailed studies, a fixed platform system is now the preferred route. Mobil Oil Canada estimates total capital costs of about $5 billion and annual operating costs of perhaps $500 million (1984 dollars). The field is expected to begin production in 1992 with an ultimate output of some 150,000 barrels (0.9 peta-

joules) per day or 10 per cent of Canada's expected 1985 production. Industry and government commitments are so high that the field will likely be developed under any price Scenario.

Best estimates of discovered reserves in the region are in the order of 1,415 million barrels (8.6 exajoules).

Oil Sands

Overshadowing all three of the new frontier petroleum regions, at least in ultimate potential, are the tremendous non-conventional reserves of very heavy, bituminous oil known to exist in the oil sands and carbonates of northern Alberta. The total bituminous oil in place is estimated at 1.25 trillion barrels (7,600 exajoules), roughly twice the known conventional oil reserves in the world. These deposits were first tapped on a commercial basis by the Great Canadian Oil Sands (now Suncor) plant at Fort McMurray. This plant, opened in 1968, mines the oil sand, separates the bitumen from the sand and then upgrades the bitumen into a high-quality synthetic crude oil. This pioneering venture was followed in 1978 by the larger but roughly similar Syncrude plant. (Appendix B presents further details of the process.) At least one, and possibly two, new mining projects are expected to be started by the year 2000 under the Base Price Case.

Only a small part of the oil sands reserve is sufficiently shallow for economic mining. Research over the past decade has shown that thermal methods of enhanced recovery will be able to produce large quantities from the more deeply buried deposits. A number of these research-type projects have been in operation for several years experimenting with different ways of heating the bitumen so that it can be pumped to the surface. One technique, the "huff and puff" method, uses alternating cycles of steam injection, then bitumen production. Continuous steam injection is also used. A third variation is to burn part of the bitumen in place (in-situ combustion) to heat the rest so that it can be pumped out. Some of these pilot projects such as Cold Lake, Wolf Lake and Fort Kent are now being expanded into commercial operations.

Currently, it is estimated that the ultimate recovery of bitumen from the shallow, mineable areas will be about 50 billion barrels (300 exajoules). Enhanced recovery from the more deeply buried deposits may yield perhaps another 200 billion barrels (1,200 exajoules). While the resource base is thus known to be huge, the raw bitumen must be subjected to intensive processing (upgrading) to create a useful feedstock for conventional refineries. The major challenges for future development, then, lie in improving the economics of recovery and upgrading.

Ontario's Oil Resources

Ontario has only minor resources of crude oil compared to its needs. Annual crude oil production in the Province is equivalent to only one day's consumption and our reserves are being gradually depleted.

While Ontario's remaining reserves of conventional crude oil are very small, there exist substantial deposits of "oil shale" which may, in the future, provide a significant source of synthetic crude oil. The total oil resource in Ontario is estimated to contain the equivalent of perhaps 80 billion barrels (490 exajoules) of crude oil. Developing even 5 per cent of this resource would provide the equivalent of a 20-year oil supply for Ontario. Recovery of shale oil from these deposits is probably uneconomic with today's technology and prices.

With technological progress, however, it is possible that at least a pilot-scale extraction plant could be in operation by the year 2000 under the Base and High Price Cases. Developing both the extraction technology and methods to minimize environmental disturbance are the challenges for the future.

Use of Pipelines

The sources of Ontario's crude oil supplies have implications for oil pipelines in Canada and the United States. Today, almost all of Ontario's crude oil supply comes from the Prairie Provinces through the Interprovincial pipeline system. Should Western Canada's supply falter, Ontario's crude oil supply can be augmented through two channels. Foreign crude oil supply can reach Ontario from the Gulf of Mexico through the United States pipeline system into the downstream half of Interprovincial's existing pipeline. Supply could also come through a reversal of Interprovincial's Sarnia-to-Montreal pipeline. This line was constructed in such a way that, with minor modifications, it can be reversed to move oil westward from Montreal to Sarnia. Oil can reach Montreal by pipeline from Portland, Maine. Thus Ontario's crude supply could be augmented by up to 200,000 barrels per day (1.2 petajoules) from East Coast offshore fields such as Hibernia or from foreign sources. This represents 40 per cent of current Ontario consumption.

Petroleum Products

A refinery is the important middle link that transforms crude oil into many different petroleum products which our lifestyle demands.

Ontario refiners produce about 90 per cent of the petroleum products used in the Province. Gasoline accounts for more than one-third of the production. The demand for gasoline strongly influences the operation of a refinery and this situation is expected to continue. (Appendix C explains some of the processes which take place at refineries.)

Gasoline is blended from a number of different streams within a refinery. Several properties such as heat content and volatility must be controlled. One of the most important of these properties is octane, which is a measure of the ignition characteristics of fuel. Many of the refinery streams that end up in the gasoline pool have extremely low octane values. In the past, refiners were able to dispose of these products by a combination of adding lead compounds and blending with high octane components. Lead renders useless the catalysts which are used to control the quality of automotive emissions. As automotive emission standards are tightened, lead must be phased out of gasoline. Refineries are thus faced with major capital costs for facilities to upgrade their low octane streams. **The continuing concern about environmental impacts in the province will lead to further changes in petroleum products.**

Unleaded gasoline, currently accounting for about half the gasoline sold in Ontario, will dominate the market by the year 2000. Since lead is also toxic, moves are underway to limit the amount of lead that is permitted in leaded gasoline. Thus even the small fraction of leaded gasoline that will remain in the product mix in 2000 will contain less lead.

With the elimination of lead, refiners will have to look for other ways to meet the octane requirements of the motor vehicle fleet.

No satisfactory substitutes have been found to replace lead compounds, and there seems to be little prospect of any being discovered and marketed by 2000. Refiners therefore will have two basic choices. They can process the low octane gasoline streams, refining them into higher octane compounds, or they can search outside the refining industry for additives which are not oil-based. Severe processing is costly, in terms of both the capital required to install the equipment and the expense of operating it. Various high octane additives such as methanol are available, but their extensive use would quickly create a demand which would exceed the available supply. **It is therefore expected that Ontario's refineries will meet the challenge of lead elimination in a variety of ways. Some will add processing facilities such as isomerization. Others will use additives such as MTBE and methanol.**

Definitions: Petroleum Products

Isomerization

A process proposed for refining hydrocarbon streams, to convert streams with low natural octane into blending stocks with higher octane properties. The actual chemical composition of the stream remains unchanged. Isomerization is one method refiners may use as an alternative to using lead additives to boost gasoline octane. To date, there is no isomerization unit in operation in Canada.

Methanol

An alcohol fuel with high octane properties that can be added to gasoline as an alternative to lead. However, the use of straight methanol at lower temperatures often results in the separation of water from the gasoline/methanol mixture, inhibiting the performance of the fuel.

Tertiary Butyl Alcohol (TBA) and Isopropyl Alcohol (IPA)

Separate alcohol compounds with high octane properties that can be mixed with methanol and added to gasoline, to enhance the octane of the gasoline. The TBA or IPA acts as a co-solvent, allowing the gasoline/methanol mixture to fully dissolve while eliminating the separation of water from the fuel mixture.

Methyl Tertiary Butyl Ether (MTBE)

An ether compound with high octane properties that can be used as an additive to gasoline, replacing the use of lead for enhancing octane. MTBE is more expensive to produce than TBA or IPA co-solvents.

A further complication will be more stringent evaporative emission standards. These could impede the use of methanol which is volatile on its own and becomes more so when mixed with many of the streams currently going into the gasoline pool. Refineries will likely solve this problem by producing tailored gasoline, specifically designed for the addition of methanol.

With the elimination of lead from gasoline, both Ontario plants for the production of lead additives are likely to close, but they are likely to be replaced by another plant to make MTBE and TBA (see the box opposite), the latter being used as a co-solvent for methanol. Production of IPA, another co-solvent, is likely to be increased.

The operation of the refinery network will continue to be driven by the demand for gasoline. Increased upgrading capacity will allow refineries to operate with greater flexibility and tailor the supply of other fuel products and of petrochemical feedstocks to match the demands of the marketplace.

At the retail level, rationalization of the service station network is likely to be continuing in the year 2000. It is likely that over three-quarters of gasoline will be sold through self-serve outlets and much of it will be computer-dispensed, payment being made by debit card at unmanned stations.

The response to lead phasedown and the advent of new fuels is likely to result in a flurry of new gasoline products being made available. However, this product differentiation will likely disappear by the year 2000. Most urban stations in the year 2000 will offer only two grades of gasoline and at least one of either propane, natural gas or methanol. Leaded gasoline may still be available as a third option at some outlets.

Discussion

Canada currently enjoys net self-sufficiency in crude oil. In order to maintain this position to the year 2000, crude oil supplies from new Canadian sources will be required by the early 1990s. In Canada, the resource potential exists in such areas as the Beaufort Sea – Mackenzie Delta, the East Coast offshore, and from such sources as the Tar Sands of Western Canada. However, all of these sources are characterized by high costs arising from complex geology and harsh environments in the frontier and offshore areas, and high costs associated with extraction and processing for oil sands.

Under the Low Price Outlook, Canada will become increasingly dependent over the next fifteen to twenty years on OPEC oil in general, and the Middle East in particular, for its crude oil supplies, due to steady demand and continuing low crude oil prices. Under the Base and High Price Scenarios, Canada's dependence on these sources is considerably reduced in favour of developing non-conventional Canadian sources.

CRUDE OIL

Ontario, as a major buyer and consumer of crude oil products in Canada, will likely enjoy a range of supply options for its purchases in the year 2000. In the Low Price Scenario, however, Ontario will become partially dependent on foreign supply.

With respect to Ontario's refining industry, it is expected that Ontario's crude oil supply will gradually become heavier. This has implications for Ontario's refinery industry.

It is possible that the year 2000 will see Ontario's refinery network relatively unchanged in terms of capacity. However, changes in feedstock slate and product demand will make necessary some radical changes in the internal configuration of the refineries.

If the price differentials between light and heavy crude oils increase, Ontario refineries will be forced to choose between purchasing the more expensive light oil or adding the capacity to accept a broader range of feedstocks, including more synthetic crude and heavier conventional crudes. Large investments may have to be made in facilities to crack heavy crude oil fractions into the lighter components which are blended into gasoline, diesel fuel, jet fuel and home heating oil

In the marketplace, the elimination of lead from gasoline is likely to be virtually complete by the year 2000, with only a small number of vintage cars operating on a diet of low-lead gasoline. This process will have a profound effect on refining operations, requiring further heavy capital investment. Unless refinery profitability improves, large capital requirements to add feedstock flexibility and to accommodate the elimination of lead may be sufficient to drive another refinery out of the market.

Under both the Base and High Price Scenarios, new non-conventional crude oil supply sources in Canada are expected to be onstream before the year 2000.

Crude oil reserves from the Mackenzie Delta and shallow Beaufort Sea will likely be developed first, since a pipeline system is already in place connecting the Norman Wells field to southern markets. This development will roughly coincide with the development of the Hibernia field off the east coast. Delivery from these sources should commence in the early 1990s.

At least one and possibly two new integrated oil sands plants could be expected to come onstream in the next ten years, and continuing development of this resource is foreseen.

If, as expected, world oil supply begins to tighten in the 1990s, more Beaufort Sea and Grand Banks discoveries will be developed to maintain Canadian supply.

Ontario's Contingency Plan

The present concentration of the world's oil supplies in a limited number of oil-producing countries makes many countries vulnerable to supply shortages. In the short term, supply can be disrupted as a result of national or international situations, political occurrences, pipeline failures, or accidents. It became apparent during the two oil supply disruptions in the 1970s that the availability of foreign crude oil cannot always be depended upon. Supplies may be adequate now, but there are no guarantees for tomorrow.

After the 1973 oil embargo, Canada and 20 other countries in the Organization for Economic Cooperation and Development (OECD) formed the International Energy Agency (IEA). An agreement was reached among members to share oil supplies in the event of a shortage. Specifically, if crude oil supplies to one or more of the IEA countries decreases by 7 per cent, all countries must reduce their demand for oil by 7 per cent. Compared to many of the IEA countries, Canada has large domestic oil supplies. However, in the event of a shortage declared by the IEA, Canadians would be obliged to share their oil with other countries.

To address Canada's vulnerability to oil supply disruptions as well as her international commitments, the Federal Government passed the Energy Supplies Emergency Act. This act established the Energy Supplies Allocation Board (ESAB). In a serious shortage, ESAB will allocate the available crude oil to refineries, and refined products to wholesale distributors and retailers. If the shortage becomes severe, ESAB would ration gasoline and diesel fuel purchased by retail customers.

Ontario supports the federal programs and is preparing its own plan to deal with shortages.

Ontario's plan is designed to lower the demand for oil in ways that will minimize impact on day-to-day life. It will ensure that the Province is prepared to effectively manage a short-term supply disruption at any time in the future.

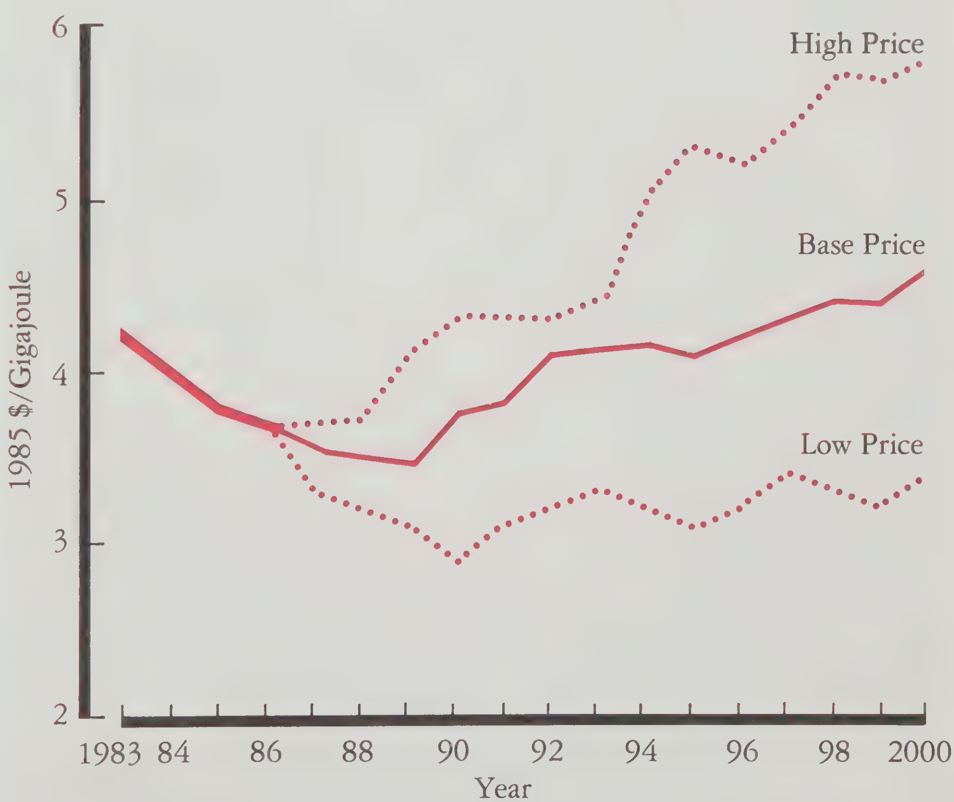
NATURAL GAS

The use of natural gas in Ontario and around the world has grown dramatically over the past 30 years. Recently, natural gas has replaced oil in a number of applications, although conservation and efficiency have slowed the growth in total demand. In the Ministry's Base Demand Outlook, by the year 2000, natural gas is expected to have captured 30 per cent of the energy market in Ontario. This implies a slow but steady growth in natural gas sales in Ontario of one per cent per annum over the period.

Ontario natural gas production is in the range of one to two per cent of annual consumption. Ninety-eight per cent of the natural gas consumed in Ontario comes from western Canada. The remainder is produced inside the Province.

The following discussion refers for convenience to three out of several possible scenarios for natural gas prices: a Base or most likely case, a High and a Low Price Case or Outlook.

Toronto Wholesale Natural Gas Price Scenarios



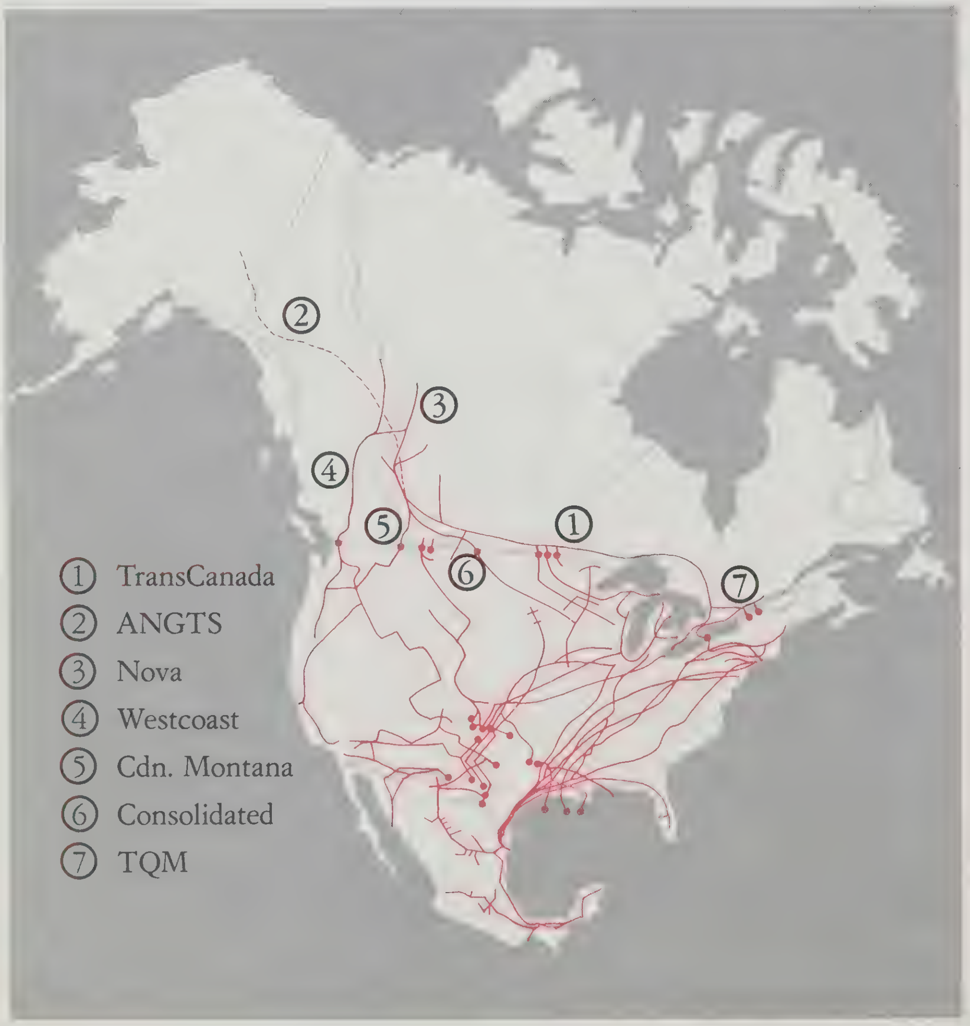
NATURAL GAS

The North American Market

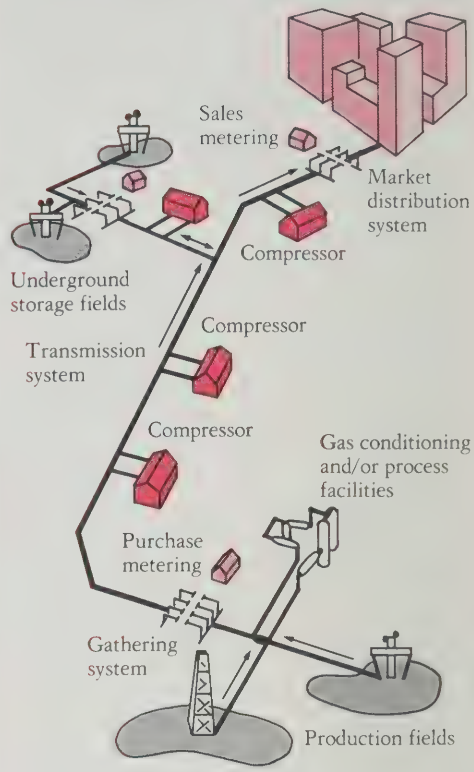
The United States is the largest developed natural gas market in the world. Americans consume between 17 and 18 trillion cubic feet (18 to 19 exajoules) of natural gas each year, or about 11 times Canada's annual consumption.

The United States produces substantial quantities of indigenous natural gas and is flanked by two producing countries, Canada and Mexico. As a result of the proximity of supply to demand, the North American natural gas market has built one of the most complex infrastructures for the pipeline transmission of natural gas in the world.

Pipeline Systems



The Natural Gas Supply System



Scale Economies, Natural Gas Transportation

The major differentiating characteristic between crude oil and natural gas is the high cost of transportation for natural gas. This has clearly shaped and will continue to shape much of the course of the future development of natural gas around the world. Although transportation costs do vary, some representative figures were recently presented in an article published in Energy: The International Journal which illustrate the nature of the transportation problem. "Gas transportation through a modern onshore pipeline might cost somewhere in the vicinity of 3¢/MM Btu/100 miles. A comparable figure might be 0.7¢/MM Btu/100 miles for a similar large crude oil line. When one moves oil over long distances by tanker, the costs go down to perhaps 0.3¢/MM Btu/100 miles. The costs of liquefied natural gas (LNG) tanker transportation over long distances are higher than any of these figures, amounting to about 7¢/MM Btu/100 miles."*

Unlike crude oil, there are no scale economies for moving small quantities of natural gas. Because of this, natural gas associated with crude oil production has been flared or left in the ground since it is uneconomic to build a transportation network to deliver the gas.

*For more information see "Gas Resources and Gas Markets: A Global View" by James T. Jensen, in Energy: The International Journal, volume 10, number 2, February 1985.

Classification of Natural Gas Reserves

Natural gas reserves can be classified as associated or non-associated. Non-associated reserves are often referred to as either: shallow basin, deep basin and tight sands.

Associated Natural Gas

Natural gas and crude oil are often found in similar geological formations. Natural gas found together with crude oil is termed "associated" natural gas and accounts for approximately 18 per cent of total natural gas production in the United States.

On average, approximately 1,200 cubic feet of natural gas is produced with each barrel of oil from conventional sources. Most tertiary methods of crude oil extraction yield little or no associated gas. Therefore, the future supply of this type of gas will depend on the split between primary, secondary and tertiary crude oil production as well as total oil production. As crude oil production in the United States declines, so will the production of associated natural gas.

Non-Associated Gas

Historically, the major source of non-associated natural gas in the United States has been shallow reserves in the Gulf Coast region of Texas and Louisiana. Non-associated shallow gas wells have accounted for over 50 per cent of natural gas production in the United States over the past 5 years. As of the end of 1983, there remains about 160 trillion cubic feet (171 exajoules) of shallow basin natural gas. This represents about 9 years worth of total current demand in the United States. Therefore by the year 2000, Gulf Coast reserves will have to be further supplemented by other lower 48 reserves to satisfy the demand in United States markets.

In other parts of the world, nations with substantial natural gas reserves, such as Nigeria or the Persian Gulf countries, do not consume significant quantities domestically and are far from major markets. Until the cost of transportation is reduced, natural gas cannot compete commercially in distant markets with other energy forms.

Natural gas from these countries usually is either flared if it is associated with oil production, or shut-in for possible future sale.

North America is therefore unique in relation to much of the rest of the world. Its substantial production has a relatively nearby market which has developed and been in balance for much of the past 30 years.

United States Supplies

The United States has large indigenous, conventional supplies of natural gas which will supply that market for many years to come. As these supplies are drawn down, the United States has several other supply options, outlined below.

Shallow Reserves

Despite the depletion of shallow onshore Gulf Coast reserves, many shallow formations have yet to be drilled. In 1983, 45 per cent of the remaining undiscovered natural gas reserves of the United States were estimated to be contained in shallow formations, mainly in the Rocky Mountain areas. These reserves are likely to come into production in the near future, since many Gulf Coast fields are already in decline.

The second-largest source of non-associated natural gas production has been offshore Gulf Coast production, which accounted for 30 per cent of all marketed production in the United States in 1983. The current estimate of offshore Gulf Coast reserves is about 66 trillion cubic feet (71 exajoules). Because of higher production costs offshore, companies are allowed to produce natural gas at rapid rates to maintain the economic viability of the wells. By the year 2000, offshore Gulf Coast reserves are expected to be in steep decline.

Deep Gas

In the United States, deep gas reserves have been discovered in the Anadarko Basin of Oklahoma and Kansas. The Anadarko Basin is reported to contain up to 200 trillion cubic feet (214 exajoules) of natural gas. Recent deregulation of deep gas prices and thus the lowering of prices from previous levels has largely reduced deep gas drilling; however, the economics of deep drilling remain more attractive than exploitation of many other unconventional reserves. Although the reserves are deep, they do not require

secondary recovery techniques as do tight sands gas reserves. For this reason they will likely be developed first, once conventional sources begin their decline.

Tight Sands Gas

Tight sands gas is found in geological formations in which the ability of the well to produce under normal conditions is inhibited. Production requires the expensive fracturing of the formation. Tight gas is present in most natural gas basins in the United States, but high production costs have precluded any significant development of these resources.

Estimates of tight sands reserves vary from 190 to 570 trillion cubic feet (203 to 611 exajoules) of recoverable gas. This represents a potential of 30 years worth of natural gas demand in the United States — a vast future resource for the United States market.

By the year 2000, the most likely tight sands formations to be in production are in New Mexico and Texas. These reserves will replace conventional shallow production near the existing pipeline grid, as they decline.

Alaska Natural Gas

The North Slope of Alaska is estimated to contain 35 trillion cubic feet (38 exajoules) of natural gas. This represents about 10 per cent of total proven reserves in the United States.

Although the Alaska Natural Gas Transportation System was approved in 1980 to deliver Alaska natural gas to the lower 48 states, it has been postponed. Prices for natural gas are currently below those necessary for its financial success. A rival project, called the Trans Alaska Gas System, would enable North Slope gas to be marketed outside of the United States. Neither of the projects look promising for the immediate future.

Mexican Supplies

Mexican natural gas accounts for approximately 21 per cent of the natural gas reserves reported in North America. Mexico therefore has the potential to become a substantial exporter of natural gas to the United States market. Under current energy policy, however, Mexico has no plans to export natural gas. Should Mexico develop this potential in the future, it could have a significant impact on Canadian exports, by displacing some market areas traditionally served by Canada.

Mexico enjoys extensive reserves of natural gas (75 trillion cubic feet, 80 exajoules) similar in size to those of Canada. Much of the natural gas produced in Mexico, however, is natural gas associated with crude oil production. In 1981, production of associated natural gas was three times that from non-associated gas fields. Mexico's natural gas production is thus

What is Tight Gas?

Unlike natural gas found in conventional producing areas, "tight gas" is found in layers of sedimentary rock that are so compact or dense that natural gas is hindered from flowing through the rock.

Recovery of the gas requires the "fracturing" of the rock formation. This may be accomplished with the use of steam or some other high pressure medium to split the rock formation and allow the gas to flow more readily to the surface.

The expense of this fracturing process increases the unit cost of the gas to the point of making recovery uneconomical. Therefore, plans to exploit the "tight gas" resource will have to await improved economics of recovery in relation to alternative supplies.

extremely sensitive to the amount of crude oil being produced, more so than any other producing region in North America. Mexico still flared natural gas as late as 1983. Total flared gas represented 20 per cent of gross production.

Proven Gas Reserves of Mexico, March 1982

Zone	Gas Reserves Tcf	EJ
Northern	11.2	12.0
Central (excluding Chicontepec)	3.7	4.0
Chicontepec Area	26.7	28.6
Southern	1.3	1.4
Southeastern	20.4	21.9
Marine	11.9	12.8
Total	75.2	80.7

Source: Petroleo Mexicanos, Memoria De Labores De 1982, Mexico, D.F., 1983.

As a large, rapidly industrializing country Mexico has become very reliant on revenue from oil production and has already suffered major economic difficulties due to the current world crude oil glut.

Natural gas in Mexico has therefore transcended its value as a fuel, becoming a difficult-to-replace cheap source of energy which frees up crude oil for exports, and serves as a basic raw material for continued industrialization.

High priority has recently been given by the Mexican Government for the elimination of natural gas flaring in the Gulf of Campeche, Mexico's major offshore crude oil field. The large diameter pipeline to onshore processing facilities is now in place and operating. Flaring from the giant Cantarell oil field ended during the third quarter of 1983. Other offshore flaring ceased at the end of 1983.

National emphasis has also been assigned to balancing of the natural gas system and the elimination of bottlenecks which have caused interruptions in natural gas service in the past.

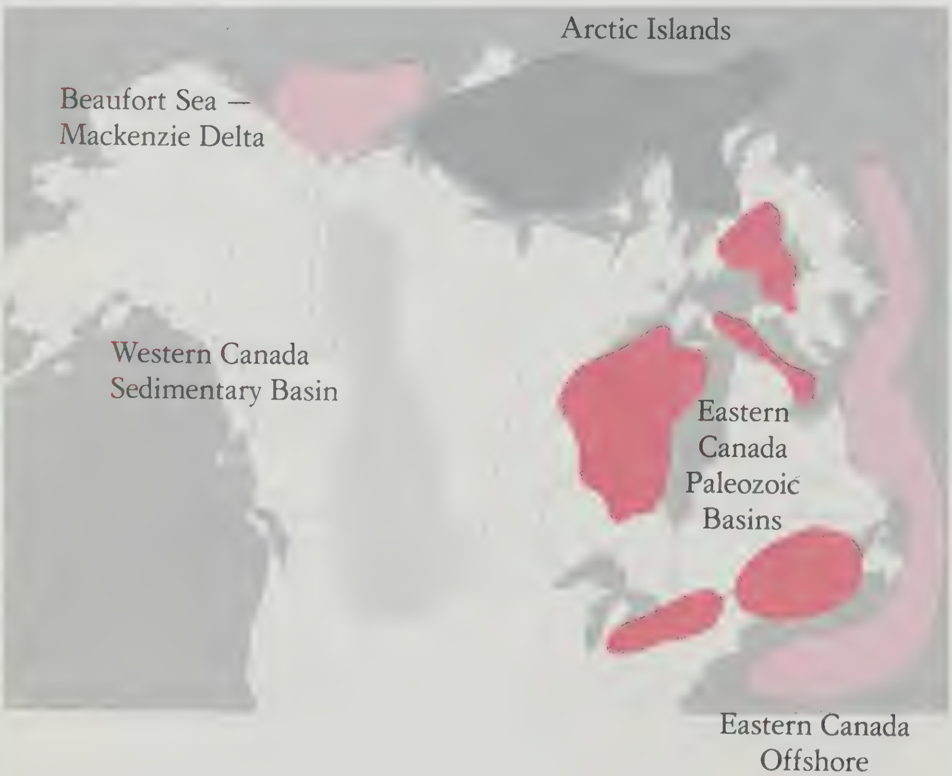
With respect to natural gas exports to the United States, Mexico's policy is clear: Exports do not, at current prices, provide the same opportunity offered by replacing domestic use of oil with natural gas. Domestic oil displacement programs allow increased crude oil exports. Mexico would have to invest heavily in pipelines to deliver natural gas to the United States, a difficult proposition at today's prices and in light of Mexico's current financial situation. This is not to say, however, that if demand in the United States for natural gas increases and prices rise, Mexico would not alter its policies.

Canadian Supplies

According to current estimates, the bulk of Eastern Canada's natural gas supply in the year 2000 will still come from the Western Canada Sedimentary Basin.

A sharp increase in world crude oil prices could lead to a greatly increased natural gas demand in the United States, as industrial users switch away from fuel oil. This could mean an earlier time frame for the development of non-conventional sources of supply discussed later in this paper. However, even under the Ministry's High Price Scenario, conventional natural gas supplies will be available to Ontario well beyond the year 2000.

Natural Gas Reserves



Western Canada Sedimentary Basin

In a Canadian context, conventional natural gas reserves usually refer to the Western Canada Sedimentary Basin which runs on a north-south axis and spans the Provinces of Alberta, Saskatchewan and British Columbia, as well as the Yukon and the Northwest Territories.

The Western Canada Sedimentary Basin currently provides almost 100 per cent of the annual Canadian consumption of 1.5 trillion cubic feet (1.6 exajoules). Ninety-eight per cent of Ontario's natural gas supplies come from this producing region, mostly the Alberta Basin.

Remaining established reserves of natural gas from the Western Canada Sedimentary Basin are presented below.

Western Canada Sedimentary Basin
Established Remaining Reserves of Natural Gas

Region	Reserves Tcf	EJ
Alberta Basin	64.5	69.2
Williston Basin	1.7	1.8
Disturbed or Deformed Belt	8.0	8.5
Northern Basins (estimated)	0.3	0.3
Total	74.5	79.8

Western Canada Sedimentary Basin
Natural Gas Potential (Recoverable)

	High Confidence		Average Expectation		Speculative Estimate	
Region	Tcf	EJ	Tcf	EJ	Tcf	EJ
Alberta Basin	39.5	42.4	64.1	68.8	133.0	142.7
Williston Basin	3.0	3.0	3.7	4.0	6.5	7.0
Disturbed or Deformed Belt	9.0	9.0	15.1	16.2	46.1	49.5
Northern Basins	1.5	1.5	5.5	5.9	29.0	31.1
Totals	54.7*	58.7*	88.4	94.9	174.1*	187.0*

* These numbers do not add arithmetically but must be summed using statistical techniques.

Source: Geological Survey of Canada, 1983

The Alberta Basin is well connected to markets. Natural gas produced in Alberta has access to the Eastern Canadian market as far as Quebec City via the TransCanada and Trans Quebec and Maritime pipelines systems, as well as most major export markets.

Natural gas sales in British Columbia rely heavily on exports to the Pacific northwest, via the Westcoast Transmission system. Saskatchewan natural gas production is not currently exported to the United States; however, the environment for exploration and development has improved substantially in the last couple of years.

Additional reserves will be delineated as further drilling takes place in known fields. The cost of developing these reserve additions, according to National Energy Board staff, lies between $1.34 and $5.36 per thousand cubic feet ($1.25-5.00/gigajoule).

After peaking in 1990 at about 3.2 trillion cubic feet per year (3.4 exajoules per year), reserves additions in the Western Canada Sedimentary Basin are expected to be in the order of 1 trillion cubic feet (1.1 exajoules) per year until the year 2005, according to the National Energy Board's latest estimates. Total production to date from this region is approximately 35 trillion cubic feet (37.5 exajoules).

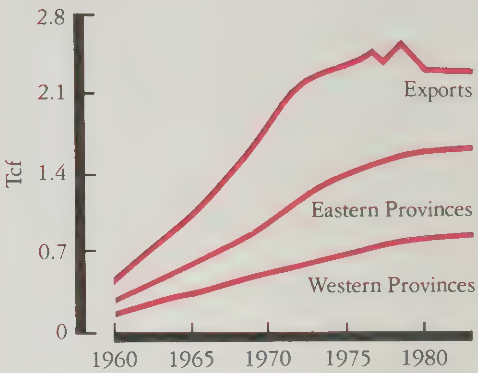
Deep Basin

Under the Base Price Outlook, Deep Basin reserves will not be economic by the year 2000. Even under the High Price Outlook, the development of Deep Basin reserves is unlikely because of the technological development required to make production of these reserves commercial.

The reserves of the Deep Basin of West Central Alberta have been the subject of great speculation since their discovery a few years ago. Although only nominal quantities of Deep Basin reserves have been recorded by the Energy Resources Conservation Board of Alberta and the National Energy Board, the Deep Basin has been estimated by some to contain as much as 300 trillion cubic feet (321 exajoules) of natural gas.

The Deep Basin is made up of non-conventional reserves sometimes called "tight gas" reserves. Most natural gas reserves have the advantage of water being present in the reservoir to assist in bringing the gas to the surface. Deep Basin reserves, however, are located below regional water and must be stimulated by hydraulic fracturing before they can be brought to the surface.

Destination of Canadian Natural Gas (1960-83)



The Deep Basin is located beneath the huge Elmworth natural gas field near Grande Prairie, Alberta. Processing, as well as gathering facilities used for the development of the Elmworth field, could be utilized for the development of the Deep Basin reserves, thus bringing down high average development costs, and ultimately the costs of production.

Drilling Costs (1983 Dollars)

Region	Cost $/Foot	$/Metre
Western Canada Basin	75 - 90	250 - 300
Foothills	160 - 210	550 - 700
Deep Basin	variable	variable
Beaufort Sea — Mackenzie Delta		
Onshore	600 - 900	2,000 - 3,000
Offshore:		
drillships	3,000	10,000
drilling platforms	3,000 - 4,000	10,000 - 13,000
Arctic Islands		
Onshore	900 - 1,200	3,000 - 4,000
Offshore	1,200 - 1,500	4,000 - 5,000
East Coast Offshore		
Venture	600 - 1,500	2,000 - 5,000
Hibernia	2,400 - 4,500	8,000 - 15,000

Source: Geological Survey of Canada, 1983.

Beaufort Sea — Mackenzie Delta

Under the Base Price Outlook, Canada could be tapping natural gas reserves from the Beaufort Sea — Mackenzie Delta region by the year 2000 if new markets develop or United States markets improve substantially. By that time, there will likely be crude oil production out of the Beaufort Sea — Mackenzie Delta area and a pipeline corridor established. This would assist in the development of natural gas reserves when they are needed.

The Beaufort Sea — Mackenzie Delta region refers to the onshore Mackenzie Delta, the Tuktoyaktuk Peninsula and the offshore extending to the edge of the continental shelf.

Reserves discovered to date have been in the gas-rich onshore Delta Area, where three large fields have been estimated to contain 3 trillion cubic feet (3.2 exajoules). Total natural gas reserves discovered in this region are estimated by the Geological Survey of Canada to contain 10 trillion cubic feet (10.7 exajoules). The greatest potential for both crude oil and natural gas is expected in the Beaufort Sea area west to the Canada — United States border extension.

NATURAL GAS

Beaufort Sea — Mackenzie Delta
Discovered Resources

(Best Current Estimate — Recoverable)

Discovery	Reserves Tcf	EJ
Issungnak	2.5	2.7
Niglintgak	0.8	0.9
Parsons	2.2	2.4
Taglu	2.4	2.6
Tarsiut	0.1	0.1
Other Discoveries	2.1	2.3
Total	10.1	11.0

Beaufort Sea — Mackenzie Delta
Natural Gas Potential

	High Confidence		Average Expectation		Speculative Estimate	
Region	Tcf	EJ	Tcf	EJ	Tcf	EJ
South Delta — Tuk Peninsula	3.3	3.6	5.0	5.4	14.2	15.2
Richards Island — Beaufort Sea	26.4	28.4	60.8	65.4	143.7	154.6
Total	30.8*	33.1*	65.8	70.8	144.9*	155.9*

* These numbers do not add arithmetically but must be summed using statistical techniques.

Source: Geological Survey of Canada, 1983

The reserves already discovered in the Beaufort Sea — Mackenzie Delta over the past 15 years or so remain unconnected to southern markets. Most estimates for the delivered supply cost of Mackenzie Delta gas to Eastern Canadian markets range between $3.86 and $5.36/thousand cubic feet ($3.60 - 5.00/gigajoule) according to the Geological Survey of Canada. This excludes taxes, royalties and the recovery of producer's exploration expenditures and profits.

During the 1970s, various natural gas pipeline projects to deliver Mackenzie Delta gas south were proposed for approval by the National Energy Board. After lengthy proceedings and intense negotiations with the United States Government, the Alaska Natural Gas Transportation System was approved and certified in 1980. The project would deliver Alaskan North Slope natural gas south to western and central United States markets. Later, the Dempster Lateral would be constructed to deliver Canadian Mackenzie Delta gas to southern Canadian markets.

Over-supply of natural gas in the North American market, which has persisted over the last several years, has delayed the northern sections of the Alaska Natural Gas Transportation System until at least 1989, and one American sponsor has withdrawn from the project. There are serious doubts that it will ever be built, particularly if other options become available.

The southern segment, called the Prebuild, is currently delivering Alberta gas exports to the United States.

In the summer of 1984, Polar Gas filed an application with the National Energy Board for approval to build a natural gas pipeline down the Mackenzie Valley from the Delta. A hearing has not yet been called. The projected capital cost of Phase I of the project is estimated to be $3.3 billion (Canadian). If approved and completed, later Phases could connect Arctic Islands and Alaskan natural gas.

These projects could develop once there is reasonable assurance that natural gas prices will be commensurate with both the cost of developing the reserves and the projected cost of the facilities to deliver these natural gas supplies to southern markets. This, in turn, will be affected by how rapidly crude oil supplies are developed in this region.

Arctic Islands

Under the Ministry's Base Price Outlook and High Price Outlook, it is unlikely that Arctic Islands natural gas would serve southern markets before the year 2000. Under a High Price Scenario accompanied by high demand, however, Arctic Islands natural gas could serve southern markets early in the next century.

The Arctic Islands region refers to four geological areas differentiated to date in the Canadian Arctic. One of the three regions, the Arctic Coastal Plain, is known to contain geology conducive to hydrocarbon development; however, the basin lies beneath the shifting Arctic Ocean ice pack. It is highly unlikely that this region would be explored in the near future to prove the geology.

The first well was drilled in 1962 in the Arctic Fold Belt on Melville Island. Since then, only thirty-two wells have been drilled to test plays in the area. In the Sverdrup Basin, one hundred and fourteen wells have been drilled, of which eighty-eight were exploratory wells, and twenty-eight were drilled offshore. The reserves in the region are not considered fully delineated at this time.

Arctic Islands
Discovered Natural Gas Resources

(Best Current Estimate — Recoverable) **Discovery**	**Reserves** Tcf	EJ
Cisco	0.1	0.1
Drake	3.5	3.8
Hecla	3.0	3.2
Jackson Bay	0.8	0.9
King Christian	0.6	0.6
Kristoffer	1.0	1.1
MacLean	0.5	0.5
Thor	0.4	0.4
Whitefish	2.0	2.1
Other Discoveries	0.8	0.9
Total	12.7	13.6

Arctic Islands
Natural Gas Potential

	High Confidence		Average Expectation		Speculative Estimate	
Region	Tcf	EJ	Tcf	EJ	Tcf	EJ
Arctic Stable Platform	3.0	3.2	8.4	9.0	16.5	17.7
Arctic Fold Belt	3.1	3.3	7.7	8.3	12.5	13.4
Sverdrup Basin	31.1	33.3	63.5	68.1	123.0	131.9
Total	38.8*	41.6*	79.6	85.4	129.3*	138.7*

* These numbers do not add arithmetically but must be summed using statistical techniques.

Source: Geological Survey of Canada, 1983

Opportunities for both oil and natural gas reserves are highest in the Sverdrup Basin. Unfortunately, the remoteness causes logistical problems resulting in very high drilling costs. Many more wildcat wells are required before the area could be delineated to determine its true geological potential.

The natural gas discoveries in the Sverdrup Basin are the most significant. Three of the natural gas discoveries in the Basin are estimated to be between 1.7 and 3.5 trillion cubic feet (1.8 - 3.7 exajoules), although the region is not fully delineated.

Of course no reserves in the Arctic Islands have yet been connected to Southern markets. It was proposed by the Arctic Pilot Project sponsors that the natural gas fields in the northern end of Melville Island be piped

south to a terminal to be liquefied and shipped by LNG tanker to market. The sponsors filed an application with the National Energy Board and were partially through the hearing when their market became uncertain and the proceedings were adjourned. It is therefore highly speculative as to when Arctic Islands gas will be connected to southern markets.

Eastern Canada Offshore

The Eastern Canada offshore will likely develop in conjunction with crude oil development in the region and at about the same time as Beaufort Sea – Mackenzie Delta natural gas reserves are developed. This will occur once markets develop, which could occur before the year 2000. East Coast offshore reserves will likely find markets in the northeastern United States, if an economical delivery method is developed for the offshore environment. It is unlikely that offshore East Coast reserves would provide an alternative source of supply for Ontario, since a delivery system would be expensive.

The Eastern Canadian offshore region trends northeast from Georges Banks to the Grand Banks off Newfoundland and shifts northwest to Baffin Bay.

As with other frontier regions, discovered reserves have not yet been fully delineated.

Eastern Canada Offshore
Discovered Natural Gas Resources

(Best Current Estimate — Recoverable)

	Reserves	
Discovery	**Tcf**	**EJ**
Scotian Shelf		
Thebaud	0.4	0.4
Venture	2.0	2.2
Other Discoveries	1.5	1.6
East Newfoundland		
Hibernia	2.0	2.2
4 Other Discoveries	0.1	0.1
Labrador Shelf		
Bjarni, North Bjarni	1.5	1.6
Gudrid	1.5	1.6
Hekja	0.4	0.4
2 Other Discoveries	0.3	0.3
Total	9.7	10.4

Eastern Canada Offshore
Natural Oil and Gas Potential (Recoverable)

Region	High Confidence Tcf	High Confidence EJ	Average Expectation Tcf	Average Expectation EJ	Speculative Estimate Tcf	Speculative Estimate EJ
Georges Bank	1.3	1.4	5.3	5.7	10.8	11.6
Scotian Shelf	3.9	4.2	17.9	19.2	35.0	37.7
Grand Banks (South)	0.7	0.8	3.2	3.4	6.3	6.8
East Newfoundland Shelf	6.0	6.5	10.2	11.0	18.7	20.1
East Newfoundland Basin	3.8	4.1	13.1	14.1	31.8	34.2
Labrador Shelf	5.6	6.0	26.3	28.2	57.5	61.9
Baffin Bay — Lancaster Sound	0.6	0.6	9.5	10.2	28.42	30.6
Totals	25.6*	27.5*	85.5	91.8	166.4*	179.0

* These numbers do not add arithmetically, but must be summed using statistical techniques.

Source: Geological Survey of Canada, 1983

The East Coast offshore drilling program has been directed towards finding crude oil; however, natural gas discoveries have been prevalent.

The most promising reserves have been in the Venture natural gas field off Sable Island in the Scotian Shelf, in association with crude oil in the Hibernia oil field in the Grand Banks, and in Bjarni and North Bjarni in the Labrador Shelf. Venture has been tested at 2 trillion cubic feet (2.1 exajoules), while estimates for Hibernia gas are 1.9 trillion cubic feet (2.0 exajoules). The Bjarni and North Bjarni are expected to yield 1.5 trillion cubic feet (1.6 exajoules).

The first deep exploratory well was drilled in the Scotian Shelf on Sable Island in 1967. Hydrocarbons were found at an exceptional depth. Since that time, seventy-nine wells have been drilled to test over 52 geological structures.

In the Grand Banks (South) area, drilling began in 1966. Twenty-eight wells have been completed; however, no wells have been drilled since 1975. Source rocks are either poor geologically or natural gas-prone. At these high exploration costs, all exploration is directed toward crude oil finds.

Drilling began in the Newfoundland Shelf in 1971, but was stopped after 10 disappointing wildcats. There was no more drilling until 1979, when success at Hibernia triggered further activity. Subsequent drilling revealed four major oil discoveries.

Exploration activity in the Labrador Shelf has identified five natural gas and condensate discoveries. The drilling season is very short due to harsh weather conditions and the presence of southward-bound icebergs.

Development of the Venture natural gas field is estimated to cost $2.5 to $3.0 billion (Canadian) to recover 2.1 to 3.2 trillion cubic feet (2.3 to 3.0 exajoules) of natural gas. An application for an export approval has recently been filed with the National Energy Board.

The reserves in the Eastern Canada Offshore have not been connected to market. With respect to the Venture field, the natural gas stream will require offshore processing before it can be shipped or pipelined to shore.

Eastern Canada Paleozoic Basins

Indigenous Ontario sources of natural gas have traditionally supplied approximately two per cent of the Province's annual requirements.

Between the Atlantic Offshore and the Western Canada Sedimentary Basin lie several sedimentary regions located within or close to the Canadian Shield. This region is composed of three areas: the St. Lawrence Lowlands, the Hudson Platform and the Maritimes Basin.

The potential of the region is not as significant as other geological areas because most of the expected hydrocarbon resources have been recovered and because the underlying geological structures are characterized by smaller pools of reserves.

Eastern Canada Gas Potential (Recoverable)

	High Confidence		Average Expectation		Speculative Estimate	
Region	Tcf	EJ	Tcf	EJ	Tcf	EJ
St. Lawrence Lowlands	0.4	0.4	2.1	2.3	5.3	5.7
Hudson Platform	0.4	0.4	3.1	3.3	14.1	15.1
Maritimes Basins	0.7	0.7	1.4	1.5	10.2	10.9
Total	1.6*	1.7*	6.6	7.1	23.3*	25.0*

* These numbers do not add arithmetically but must be summed using statistical techniques.

Source: Geological Survey of Canada, 1983

The St. Lawrence Lowlands contain the oldest oil and gas plays in Canada. Many small oil and gas fields are spread across southern Ontario in old reservoirs. Some of these reservoirs are used for natural gas storage. During the winter, the supplies are drawn down to meet peak demand. Remaining natural gas reserves as of 1982 were 0.3 trillion cubic feet (0.32 exajoules) in Southern Ontario.

Since the Oil Springs discovery in 1858, 40,000 oil and gas wells have been drilled in Ontario. Exploration has recently moved into offshore Lake Erie where more than 1,000 wells have been drilled. Exploration in the St. Lawrence River area has shown very little promise.

In Hudson's Bay, the first wells were drilled in the 1940s. Other wildcat wells have been drilled in the offshore in 1969 and as late as 1974. While no commercial hydrocarbons have been found in the region, two wells are being drilled in 1985.

Discussion

Canada, like North America, is fortunate to enjoy substantial reserves of natural gas, not only from conventional areas, but from promising unconventional sources, should the need arise.

At current levels of consumption, and honouring all existing export commitments, Canada's currently connected supply base has been estimated to be sufficient to satisfy projected demand for more than 30 years — well beyond the year 2000.

Ontario, as the major consuming province in Canada, is therefore assured of the availability of reasonably priced, conventional natural gas to satisfy the demand in the Province well beyond the year 2000.

Even under a scenario of high domestic and export demand, conventional reserves will provide the base for supply to Ontario in the year 2000. However, new supplies will be increasingly required as conventional reserves are drawn down.

Following the commencement of the decline of the conventional reserves in Western Canada, Ontario would have several options for its natural gas supply. Depending upon the outcome of current developments, a continental natural gas market could form, whereby Ontario would become part of a larger North American market. Gas would freely flow between Canada, the United States and Mexico.

Beyond conventional natural gas supplies and reserves additions, non-conventional reserves in either Mexico or the United States may be more economically feasible to develop than some non-conventional Canadian reserves.

The development of most frontier and offshore natural gas reserves in Canada will be dependent upon the presence and development of the crude oil reserves that are discovered as well as the market opportunities available. Under the Base Price Scenario, these natural gas reserves are unlikely to be required until beyond the year 2000. However, should markets expand and prices increase, these reserves could be in production by 2000.

In Canada, East Coast offshore and shallow Beaufort Sea — Mackenzie Delta crude oil reserves will likely be among the first unconventional reserves to be developed prior to the year 2000. Natural gas production could follow this development on a field-by-field basis as long as markets are available for the production. Under the Base Case Outlook, this will not occur until beyond the year 2000. However, under a high price, high demand scenario, or if a special deal was struck between the producer and an end user, the development of these natural gas reserves could occur much earlier.

East Coast offshore reserves will likely be exported to the United States' northeast market, if an economical delivery system can be built. East Coast offshore natural gas reserves will likely not be available to the Ontario market, since no onshore pipeline facility exists to ship the gas west from the Maritimes to Ontario.

Beaufort Sea — Mackenzie Delta natural gas reserves, however, should provide Ontario with a future alternative supply base to western Canadian supplies, although the price will be higher. Crude oil production and delivery, expected prior to the year 2000, would provide a pipeline corridor down which a natural gas pipeline could be constructed in the future, when supplies are needed. This pipeline could tie-in to existing Alberta facilities and the TransCanada system, which should have sufficient spare capacity by that time. This development would not take place, however, until beyond the year 2000 when markets are expected to require supplemental supplies.

Once in place to serve initially a United States market, this pipeline system also would be available to serve future Ontario requirements.

Non-conventional reserves of the Deep Basin could be developed prior to frontier resources, depending upon the development of the necessary technology to make the reserves economically feasible to produce. Deep Basin reserves are located in close proximity to currently developed natural gas fields and would enjoy the advantage of utilizing not only production facilities but existing gathering and transmission systems. This would serve to reduce the cost of these reserves substantially. Using the Base Price Outlook, Deep Basin reserves are unlikely to be developed until well beyond the year 2000 because of their associated high costs. However, should natural gas demand rise substantially in Canada and the United States and prices rise also, the technology could develop sooner than expected.

Arctic Islands natural gas will likely be very expensive to develop and therefore would only be available to Ontario and other Canadian and United States markets when prices so dictate. Crude oil finds in the Islands would likely have increased the possibility of earlier natural gas development; however, most discoveries have been highly gas-prone.

OTHER SOURCES

OTHER SOURCES

Although the crude oil, natural gas, and electricity sectors dominate energy supply planning in Ontario, there exists a wide variety of other energy sources in use. Energy from wood and organic waste, solar energy, coal, lignite and peat, fusion power, hydrogen, and various alternative transportation fuels are all discussed in this Section.

Global Trends

In many parts of the world these other energy sources are likely to be dominated by "non-market" energy supplies. These include the power provided directly by animals, the wind harnessed to power sail boats, and the energy released by burning wood gathered by the user.

While many of these non-market energy sources are likely to continue to be important even in the year 2000 for many countries, they are unlikely to play a significant role in developed countries.

In alternative futures where energy demand growth is rapid, or where conventional energy prices are high, a variety of "other energy sources" will become more important and a number of "new" energy industries will emerge or increase in size by the year 2000. Perhaps the most significant of these new energy "supply" industries in the industrialized world will be the one devoted to promoting the improvement of the efficiency of energy use.

Improved energy efficiency occurs in all of the futures considered for this paper. The rate of change to more energy-efficient equipment can be very sensitive to energy prices and to rates of demand growth. Projections of the changing efficiency of energy use in Ontario are made in the companion paper on energy demand, **The Shape of Ontario's Energy Demand.**

Increasing energy efficiency means that significant financial resources will be employed to reduce the need for fuels and power. It may cause shifts in the size and types of markets for conventional and alternative energy supplies. One example may be in the residential sector where the introduction of energy-efficient homes has already decreased the potential market for active solar space heating.

Programs designed to increase end-use efficiency may also be used by energy supply industries since such programs may in some cases provide a tool for increasing profitability, reducing the need for major capital expenditure or preserving market share.

Wood and Biomass

In medium energy price and demand futures, wood is likely to emerge as a source of commercially-traded energy in a number of countries. Sweden, Canada and Brazil are all likely to have sectors that obtain over 5 per cent of their energy supplies from wood. Wood will be used to the greatest extent in forest-related industries, but in the colder climates, wood space heating will become increasingly popular. Undesirable localized environmental effects, such as an increase in smog on windless days, may become more intense. Energy plantations, where fast growing trees or bushes are "harvested" in 5-year cycles, are likely to remain uneconomic.

Energy From Waste

A number of countries now make use of facilities which burn municipal garbage to produce electricity and/or heat as a by-product. Several hundred such plants exist around the world today, many of which have been operating for over 40 years. Municipal waste disposal plants may, in 2000, provide a significant amount of a region's energy supplies and will help to alleviate many of the landfill and pollution problems associated with other forms of garbage disposal. While higher energy prices would accelerate the development of municipal waste disposal plants, only extremely low energy prices are likely to seriously delay their use, since environmental concerns are a driving force behind their development.

Solar Energy

A strong international solar thermal energy industry is likely to exist in the year 2000, in a wide range of energy futures. The industry will probably serve a market for domestic and commercial hot water systems and industrial process heat needs. The widespread use of active solar heating systems for residential space heating is unlikely.

In tropical countries, the vast majority of buildings which require hot water are likely to use solar heating to meet their hot water needs. In more moderate climates, it is likely that only those buildings constructed during the 1990s will use solar systems to meet hot water needs.

In Canada, the solar industry began to grow rapidly in the late 1970s, a period when major price increases for conventional energy sources were expected. A number of market niches now exist and a Canadian solar industry has been established. Current sales in Canada are estimated to be slightly over 10 million dollars per year.

Substantial growth in the Canadian market for solar heating systems is only expected in futures involving high energy prices.

Energy Plantations

Energy plantations are farms where trees are planted and harvested for energy purposes on a short rotation cycle (2 to 12 years). Hybrid poplar trees with very fast rates of growth have been developed for these plantations. The trees can be planted on marginal farmland that is, for example, too stony or wet for conventional farming. The plantations are intensively managed to ensure crop yield. The whole tree is harvested, chipped and burnt to produce steam. The steam can be used directly or it can be used to run a steam turbine and generator to produce electricity. In 1981, the Ontario government established the Ontario Tree Improvement and Forest Biomass Institute in Maple to study genetics, forest production and technology related to tree plantations.

Solar Heating: Principles

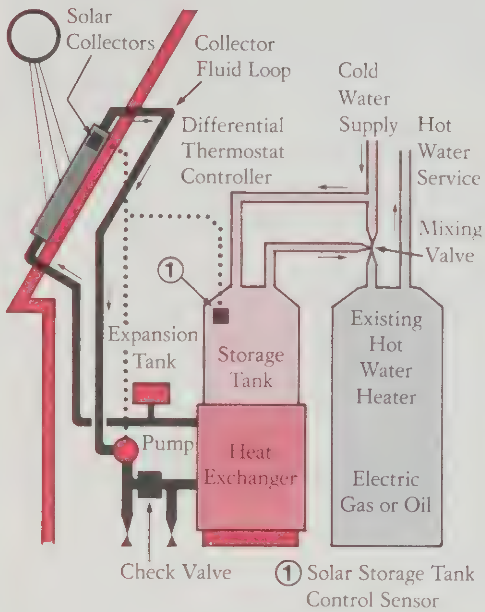
The sun's energy can be trapped in a variety of ways. Passive solar "devices" include properly oriented windows and skylights. Active solar devices make use of solar collectors, heat transfer mechanisms and usually, heat storage systems.

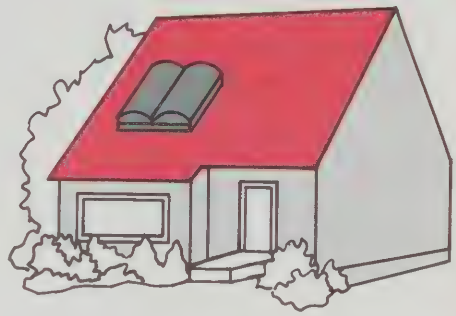
The illustration shows a packaged solar hot water heating system for a single family home. These can be cost effective in some circumstances. Experience in Ontario suggests that larger systems to help meet industrial process heat needs may be even more economic.

The Greenhouse Effect

The atmosphere is composed of molecules of oxygen, nitrogen, carbon dioxide, water vapour and other particles which absorb energy at certain wavelengths. Most of these gases, including CO_2, are transparent to solar radiation, but absorb the re-radiated energy from the Earth's surface. Together, CO_2 and water vapour molecules absorb most of this long-wave energy. As fossil fuels are burned, the levels of CO_2 in the atmosphere increase due to CO_2 emissions. This creates a warming or "greenhouse" effect similar to the warming produced in a glass enclosure when heat loss is impeded. If the concentration of CO_2 were to double, this could cause the Earth's temperature to rise a few degrees Celsius. The global effect would vary with latitude, but would be especially significant in the Polar regions.

Solar Energy





- 2 or 3 collector panels
- net area 4.6 - 5.6 square metres (50 - 60 square feet)
- collectors single-glazed with selective surface or flat black paint
- 310 litres (68 gallons) water storage tank
- wrap-around heat exchanger, 1.6 square metres (17.5 square feet)
- pump, valves, controls, and expansion tank supplied as part of the package to partially heat the hot water

Coal

In medium price and demand futures, it is likely that coal, particularly for steam generation, will regain some of the importance it lost in the 1970s. It is likely to be used widely on all continents, and world trade is likely to exist with Australia, Canada, the United States, South Africa and Colombia being major exporting nations. A large portion of the non-utility use of coal is as a raw material in the steel industry.

Acid gas, created by the combustion of fuels containing sulphur, such as coal, is likely to remain a problem even with the use of improved combustion technology. A longer-term concern, which is likely to become more important, is the possible warming of the globe due to the production of carbon dioxide (CO_2) from large-scale burning of hydrocarbons. The accumulation of carbon dioxide in the atmosphere produces a phenomenon known as the "greenhouse effect".

Although coal burned to raise steam may be a significant contributor to these environmental problems, other contributions result from gasoline and diesel combustion in the transportation sector.

Lignite and Peat

Lignite, which is a lower-grade coal, will continue to be used in many areas to fuel electricity generating stations. Peat will continue to be used locally where the resource is available. Major programs may develop in the lesser-developed countries which cannot afford to burn natural gas or oil.

Fusion

Fusion power is likely, in the year 2000, to remain an elusive energy source.

By 2000, experimental reactors may have been built and will provide better data for estimating the cost of harnessing fusion power commercially. The rate of development of fusion power will be largely unaffected by the events postulated in the alternative futures considered in this paper.

Fusion may be used early in the 21st century if breakthroughs are made in the technology currently being researched. Work is now in progress to dramatically reduce the scale of the technology required to commercialize fusion. If successful, this work could accelerate the development of a working reactor. (Two technologies for harnessing fusion power are described in Appendix D.) It is unlikely, however, under any of the futures considered, that fusion could make a substantial energy contribution by the year 2000.

Hydrogen

Hydrogen has been touted as the fuel of the future. Hydrogen is not an energy source in its own right, but rather a fuel — a way of storing and transporting energy. Hydrogen can currently be produced using electricity as an energy source and water as the raw material. Other processes use hydrocarbons as the raw material in feedstock. In the former process, conversion efficiency is not high, so that the extent of the future use of hydrogen is tied to the availability of abundant, low-cost electricity. In the latter case, the raw material costs are high. Projects designed to demonstrate lower-cost methods of producing hydrogen — for example, using sunlight to split water, and thus to produce hydrogen — have not yet been successful.

Alternative Transportation Fuels

Transportation in the industrialized nations of the world depends on oil. To reduce this dependency, a number of alternative fuels have been investigated.

Brazil has had a thriving Alternative Transportation Fuel industry since the 1970s. To conserve foreign exchange, sugar cane crops were used to produce ethanol to supplement their imported gasoline. Though

foreign exchange may be less of a worry by the year 2000, it is likely that nearly all cars in Brazil will run on ethanol.

California and other western States may also become major users of alternative fuels. They will be driven by the need for less polluting transportation fuels.

By 2000, it is likely that the North American motor products industry will have sufficient experience with the new fuels in a variety of climates and over a range of different driving regimes to offer full warranties on vehicles using the new fuel types.

The fuel supply infrastructure will be in place, and the future may bring a rapid consumer adoption of alternative fuels as their relative economies change.

Alternative transportation fuels are likely to develop in futures which include a wide range of international crude oil prices. In many areas, their development is likely to be driven by environmental issues or local economic conditions.

Ontario's Use of Unconventional Energy

In Ontario, "unconventional energy" will supply a growing amount of the Province's energy needs. The possible contribution of some of the unconventional and alternative generation types to the electricity grid have been discussed in the Electricity Section.

Wood

It has been estimated that in Ontario, wood currently displaces over 100 million dollars worth of fuel oil, natural gas and electricity from the home heating market. In industry, especially the forest products industry, the use of wood waste displaces over 400 million dollars worth of fuel. Wood is a major energy resource now. In the Ministry's base Outlook, wood and wood waste provides 4 per cent of Ontario's end-use requirements in 2000.

Energy From Waste

In Ontario, energy can be extracted economically from waste in a number of circumstances. Opportunities exist in the pulp and paper industry as discussed above; at large industrial complexes; in agriculture; and from the combustion/disposal of municipal waste.

In large industrial complexes, waste may have a substantial energy content. In Ontario, in 1985, over a dozen "energy from waste"

projects are being considered for development. Their total estimated capital cost exceeds $300 million, and their annual energy output would exceed the annual energy requirements of a city the size of Peterborough.

Though there is a finite amount of such waste material available annually, it can make a meaningful contribution to Ontario's energy supplies. The economic success of plants expected to be in service by 2000 will be determined not only by the price of the fuels against which they compete, but also by their success in reducing environmental problems associated with waste disposal.

The use of agricultural waste also has potential as a limited source of energy in Ontario. Again, the success of devices such as anaerobic digestors (which break down animal wastes and produce substantial amounts of a gas capable of supporting combustion) will be determined largely by the value placed on their ability to reduce environmental concerns. Such problems as odour arise as farm operations become larger, and homes are built closer and closer to them. Intensive use of crop waste could have detrimental effects on the soil, and increase the need for the use of fertilizer.

The recovery of energy during the disposal of municipal waste potentially could annually displace over 300 million dollars worth of conventional fuels in Ontario.

The extent to which energy is recovered from this waste depends on future energy prices as well as the future costs of alternative means of disposing of municipal waste (e.g., landfill or incineration). The Ministry's Base Outlook projects an energy contribution worth over $20 million per year in the year 2000.

Two conversion processes are feasible for Municipal Solid Waste. The first involves direct burning of garbage in incinerators. The Solid Waste Recovery Unit (SWARU) in Hamilton, with a capacity of 600 tons per day, was the first plant of its kind in the world. The second conversion process is the production of refuse-derived fuel from which dry solid fuel or pellets are produced. Existing coal-burning equipment or adapted boilers can use the pellets as fuel. Testing of this method has been undertaken at the Experimental Plant for Resource Recovery in Downsview, Ontario.

Biomass Conversion Technologies

There are a number of available technologies that can convert biomass to various forms of energy. The energy in biomass and waste may be converted into space heat, process heat, mechanical power and electric power. These conversion technologies are briefly described as:

Combustion

The burning of material to produce heat. Burning can be carried out either directly or after gasification.

Acid Hydrolysis

The conversion of a material containing cellulose, usually wood or straw, into sugars through the application of an acid.

Enzymatic Hydrolysis

The conversion of a material containing cellulose into sugars through the action of special enzymes.

Destructive Distillation

The conversion of wood into charcoal.

Anaerobic Digestion

The conversion of slurried organic material, in the absence of oxygen, into combustible gas containing methane.

Hydrogasification

The conversion of biomass in the presence of hydrogen to yield gas which can be upgraded to pipeline-quality synthetic natural gas (SNG).

Gasification

The heating of organic matter in the absence of sufficient oxygen for full combustion produces a combustible gas composed of hydrogen, carbon monoxide, and alkalines (e.g. methane) as well as non-combustible CO_2 and NO_2.

Hydrogenation/Carboxylolysis

The conversion of biomass to a liquid fuel or synthesis gas through the addition of carbon monoxide/hydrogen alkaline catalysts for hydrogenation and carboxylolysis, respectively.

Liquefaction

The application of heat to organic matter in the absence of sufficient oxygen for full combustion and at certain temperature, pressure, residence time results in the production of a synthetic liquid fuel oil.

Alternative Transportation Fuels

The transportation sector consumes almost half the oil consumed in Ontario. To decrease the dependence on gasoline, other transportation fuels are being tested for use in internal combustion as well as modified engines. Propane, natural gas, and alcohol fuels are all alternative transportation fuels.

Propane

Propane is derived from natural gas or petroleum refining. There are over 60,000 propane vehicles in Ontario with the majority of vehicles being commercial fleet vehicles including automobiles, light and medium weight trucks. Propane's lower energy content (up to 20 per cent more propane fuel than gasoline is required to travel a given distance) is offset by its lower cost compared to gasoline.

Natural Gas

Natural gas can be stored as either compressed natural gas or liquefied natural gas (LNG). Further technical and commercial development is needed for LNG and the commercialization of natural gas vehicles is still in the early stages. The range of a natural gas fuelled vehicle is limited to less than 200 kilometres between refills. Natural gas as a vehicle fuel currently costs almost half as much as gasoline.

Alcohol Fuels

These include methanol derived from natural gas, and ethanol which can be produced from sugar, corn and waste products. Both are used as octane boosters in blends with gasoline to improve fuel economy and reduce engine knock. Methanol produces about half as much energy upon combustion as gasoline while ethanol produces about 66 per cent as much energy.

Solar Energy

In Ontario, the current use of active solar energy systems is only economic in a number of small markets (the heating of swimming pools, and some industries where large amounts of low temperature heat are required). Development programs during the 1970s and early 1980s dramatically improved the cost-effectiveness of many types of systems and applications. Given the changed outlook for energy prices, the extension of markets is likely to be slow. The contribution of active solar heating systems to Ontario's energy supply by the year 2000 in the Base Outlook is likely to remain small: less than 1 per cent of total provincial needs.

In spite of this small contribution from active solar heating devices, solar energy currently contributes the equivalent of more than a third of a million barrels of crude oil equivalent to Ontario's energy supplies in what is termed passive solar gains. Solar energy contributes to buildings' heating supplies by heating walls and passing through windows exposed to the sun to heat materials inside the house. The use of south-facing windows and proper building design can mean that over 30 per cent of the energy needed for heating in new homes could come from the sun.

Coal, Lignite and Peat

Coal is an important fuel in Ontario. It is used both for electricity generation, and as an energy source and feedstock in the steel industry. Excluding its contribution for electricity generation it accounts for over 20 per cent of industrial end-use energy. The discussion of coal-fired electricity generation plants and alternative generation in the Electricity Section describes improved methods of handling and burning coal which would improve its economics and its environmental acceptability.

Ontario has large deposits of lignite in the north, however, extensive use of this lignite is not expected by 2000.

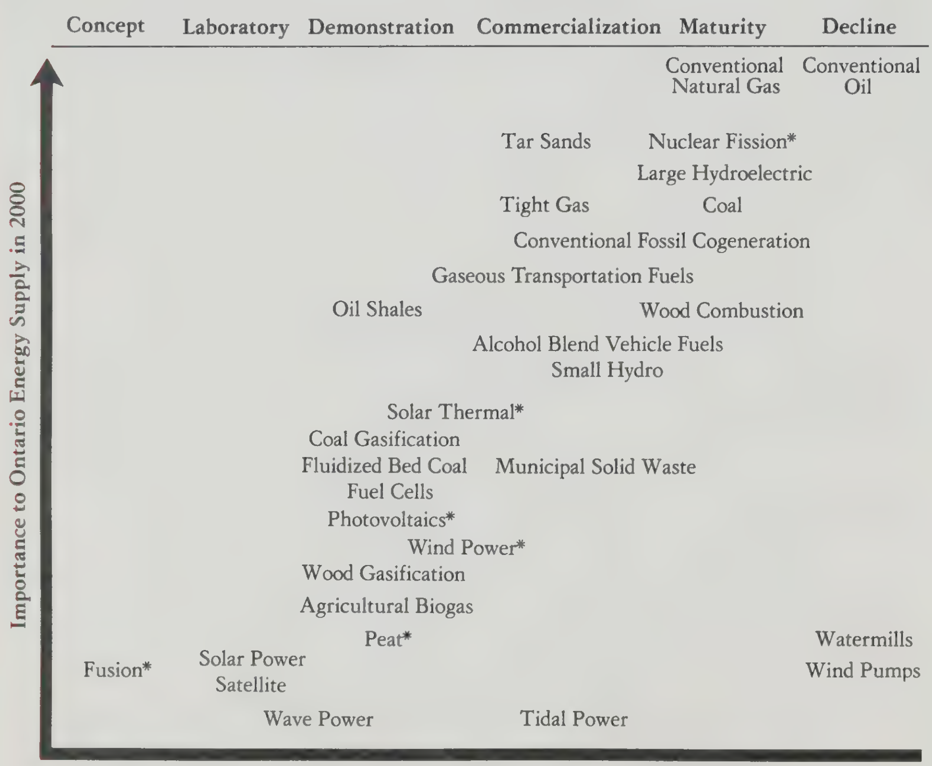
Alternative Transportation Fuels

In Ontario, in the Base Outlook, alternative transportation fuels are projected to displace 7 per cent of crude oil-based transportation fuels. Propane and natural gas account for half of this displacement and methanol, mostly in blends, the other half. Natural gas vehicles will, in this Scenario, be used commonly in commercial van fleets. Methanol, used to extend oil supplies, is likely to become an important blending component being used by major refineries. The major automotive manufacturers will likely offer cars, buses and trucks designed to use neat methanol.

Discussion

New technologies for harnessing energy sources — in fact, technologies and innovations generally — move along a cycle which starts with their theoretical or conceptual development and progresses through commercialization to radical change or obsolescence. The options available for speeding the introduction of a given technology and the confidence which exists in predictions about success both depend upon the position in the technology development cycle. Other key factors include the characteristics of the technology itself and the market in which it must compete.

Energy Supply and the Product Development Cycle



* These supply sources have a virtually unlimited resource potential in Ontario.

The Need for Research

The least developed technologies are those which depend on proven principles, but which have not been proven outside the laboratory. This group includes fusion power and various novel means of producing hydrogen.

Fusion, for example, could be very important in the future. The ultimate success of fusion projects is, however, very uncertain. One of the great attractions is the existence of a cheap and widely available supply of fuel which can, in theory, be obtained from water. If fusion were to be developed to a commercial stage, it could make a major contribution to Ontario's energy security. The date of commercially competitive fusion systems is very uncertain, since successful energy production from fusion reactions has yet to be proven even in the laboratory.

Hydrogen production methods also provide examples of technologies that could be important in Ontario in the future. If large quantities of low-cost electricity were available in the future, hydrogen fuel could be produced in quantity and might find a substantial market in Ontario. Equally, if lower-cost means of producing hydrogen fuel are perfected, a large market might be found. Major uncertainties about the future availability of low-cost electricity for this purpose and about technological breakthroughs do exist, however.

Appropriate levels of funding for fusion for hydrogen-related research, and for other technologies, are very difficult to establish. Given the uncertainties, allocations for research into one technology with high potential must be balanced against allocations for research into another technology, which may have less potential but appears more certain.

Assisting Technology Development and Demonstration

Another group of technologies would include those which have been proven in the laboratory but which have not yet been widely commercialized. These technologies await further development, cost reduction, or marketing before they can be put into commercial service on a large scale.

Technologies in this group that are relevant to Ontario include fuel cells, photovoltaics, and wind power for electricity generation, and extend to solar thermal technologies, wood gasification, electric vehicles and various alternative transportation fuel options. Conservation technologies and energy-efficient technologies, many of which could be included in this grouping, exist over the entire range of the product development cycle.

It is unlikely that these new energy technologies will displace more than a small fraction of the conventional fuel use predicted for Ontario in the year 2000. They could, however, provide the basis for an expanding sector of the economy.

In the post-2000 period, it may well be that these technologies are used to meet increases in energy demand within the Province.

Given this longer time frame, and given the opportunities that exist now, what are the policy options that exist?

Many of the unintended barriers to the introduction of new energy sources are not economic. They can be institutional — the fact that technologies do not naturally fall into any existing industrial infrastructure. They can be environmental — the fact that no-one fully understands the environmental impacts associated with the technology over its life. Alternatively, they can be technical, financial, or regulatory. Many analysts suggest that as a technology becomes economic, the government can play a useful role in reducing many of these barriers.

A useful example relates to energy-efficient technologies. Many exist to increase the efficiency of energy use, and many are economic in a variety of markets, but it is not clear how long it will take to introduce these technologies into the economy. Programs in the United States, such as home insulation programs undertaken by the Tennessee Valley Authority, suggest that with support from existing utilities and governments, changes involving the most economic technologies can be rapid. As this "cream" of the energy efficiency crop disappears, change is likely to be slower. In other jurisdictions, the encouragement of improved energy efficiency may have been simplified by the existence of "energy service" companies rather than more specialized oil companies, or gas and electricity utilities which operate in Ontario.

The rationale for government involvement, the acceptability of using regulated rates for encouraging energy efficiency, and the adequacy of the current supply structure for encouraging conservation and the development of efficient use technologies, are all questions which arise in this regard.

Accelerating Commercialization

A third group of technologies can be defined to include those which are economic in substantial market niches, and which are not likely to experience significant cost reduction or technological change. These technologies, which are typically in the early stages of commercialization, include propane engines and natural gas vehicles, municipal solid waste plants, wood densification, and a variety of oil and gas recovery techniques. The future of these technologies could be difficult to predict because of uncertainties about competing technologies or rival energy supplies.

Ontario Ministry of Energy Programs for Energy Technologies

Biomass/Carbon Resources

- cost-sharing assistance to commercial and industrial users of wood combustion systems
- financial assistance for coal combustion studies
- research into hybrid poplars
- demonstration of new utilization technologies

Agriculture

- demonstration of energy-efficient technologies including biogas systems, improved ventilation methods, and cultivation techniques
- cost-sharing assistance for grain drying applications
- greenhouse assistance program

Municipal Solid Waste

- landfill research
- demonstration of new technologies, and assistance with feasibility studies
- financial assistance to large-scale application

Solar

- cost-sharing assistance to commercial and industrial users of solar thermal systems
- technical assistance to the solar energy industry in developing cost-effective technology
- assistance to the residential building industry to commercialize passive solar/low energy housing
- demonstration of new solar technologies

Small Hydro

- demonstration grants
- municipal small hydro feasibility assistance
- northern small hydro assistance

Cogeneration

- cogeneration retrofit and upgrading in institutional settings

Industrial Process Efficiency Improvement

- technical and financial assistance for feasibility studies of energy-efficient processes

Transportation Fuels Development

- natural gas vehicle demonstration
- propane vehicle demonstration
- methanol vehicle demonstration
- financial assistance for research and safety studies

Electro-Technologies

- small wind systems, and wind diesel systems for supplying electricity in remote areas
- electro-heat, plasma arc, and cell membrane technologies for efficient industrial use of electricity
- electric road transport

Hydrogen

- assistance to the Institute of Hydrogen Studies in projects such as hydrogen safety, bulk storage fuel cell development, etc.
- hydrogen engine development

Fusion

- financial assistance to the Fusion Fuels Technology Program (managed by Ontario Hydro)
- financial assistance for fusion research

In the Ministry's Base Outlook, a number of technologies will continue to develop. The penetration into the markets of some technologies which would be hastened by higher energy prices is also driven by other concerns. Alternative transportation fuels are likely to continue to develop because of their potential for reducing air pollution. Municipal solid waste plants might also continue to develop because they are driven by the need for appropriate methods of waste disposal. Photovoltaics may also continue in markets such as remote sites, where maintenance rather than fuel costs dominate the economics. Wood use for energy will also continue in the pulp and paper industry. Wood heating in the residential sector is likely to continue where low-cost wood is available.

In the Ministry's High Demand Scenario where oil and other energy prices remain low, the introduction of new technologies is delayed in some applications. A buoyant and expanding economy built, in part, on low energy prices, provides opportunities for new technologies to be used, but less risky options are more likely to be chosen. Research and development funding is not likely to focus on energy technologies; this further slows the development and introduction of new technologies and the industrial infrastructure necessary for their use.

On a regional basis, a major concern in a low energy price future is that small industries, set up to market technologies at the early stages of commercialization, would disappear. This would likely be the fate of many Canadian firms marketing solar thermal technologies, wind power, wood gasification and wood pelletization. The loss of the experience base associated with the demise of these companies could further retard the introduction of new energy sources.

In futures with high crude oil and natural gas prices and high energy demand, the price and concern about energy security, could accelerate the introduction of "other" energy sources. Substantial "niche" markets exist at a world level for windpower, solar thermal technologies, photovoltaics and other technologies. The effect of higher energy prices would be to expand these niche markets, thus reducing product development risks. More funding would be devoted to research and development, thus accelerating the improvement of these technologies.

There is, however, a limit to how quickly new technologies can be introduced. Higher crude oil prices would increase the rate of development of new technologies. In tropical countries with embryonic energy supply infrastructures, the acceleration would be quite dramatic. While this would be important to the industries involved, the contribution of new energy sources to world energy supplies would still be minor compared to the contributions made by more conventional technologies.

CHALLENGES

CHALLENGES AND OPPORTUNITIES

This review of Ontario's energy supply options shows that adequate supplies of crude oil, natural gas and electricity are expected to be available to meet the Province's energy needs. This will allow choice among energy supply sources and mixes for the Province.

Electricity

Ontario will probably continue to have surpluses of electricity available to it through the rest of the 1980s and into the early 1990s. The plentiful supplies result from the major capital construction program begun in the 1960s and 1970s and from continuing low electricity demand growth rates.

However, because of the long lead time associated with the development of new generation facilities or demand reduction programs, decisions about which options to pursue to ensure adequate supplies in the late 1990s and beyond 2000 will be needed in the late 1980s. For example, if additional nuclear facilities were required for the year 2000, decisions about station size and location would be needed soon.

Alternatively, decisions may be made to pursue other options. Ontario will be in the fortunate position of being able to utilize new hydraulic facilities, electricity purchases, alternative generation options, and/or various conservation options to ensure system reliability in the late 1990s.

The challenge facing electricity planners is to maintain a system which provides electricity at low cost but also retains enough flexibility to respond to the changing electricity needs of the Province. Electricity is expected to increase its market share, and will be an important factor in increasing industrial productivity.

Crude Oil

Under the Base Outlook, crude oil prices are expected to remain below levels experienced in the early 1980s. Although new Canadian supplies are likely to come into production and Canada may have net self-sufficiency, Ontario refiners will probably take advantage of the new decontrolled environment and purchase an increasing amount of crude oil from international markets, as profitable opportunities arise.

Conventional western Canada oil fields will continue to be an important source of Canada's crude oil supply. Increasingly through the 1990s, however, new supply sources will be needed. This new supply is expected to come from heavy crude oil upgrading, integrated oil sands plants, the Mackenzie Delta — Beaufort Sea and the East Coast Offshore, all of which will be high cost sources. Beyond 2000, the Arctic Islands may also provide an important supply contribution.

CHALLENGES

Whether to maintain Canadian net self-sufficiency in crude oil or to become more dependent on offshore resources will continue to challenge policy-makers in Canada. For Ontario, the major buyer of crude oil supplies and consumer of crude oil products in Canada, this challenge requires the balancing of the higher cost of supply security against the lower cost of imported oil projected in the Ministry's Base Price Outlook.

Canada's crude oil supplies will continue to become heavier on average. This will have important implications for Ontario's refineries since intensive processing is required for heavier crude oil.

In the marketplace, the elimination of lead from gasoline is likely to be virtually complete by the year 2000. This will pose an additional challenge to refiners to accommodate the elimination of lead, as well as the additional feedstock flexibility required.

Natural Gas

In the year 2000, ample supplies of natural gas will be available to Ontario. Non-conventional reserves could also begin to be developed and included in Ontario's supply mix. These reserves, however, will carry with them a higher cost than conventional western Canadian natural gas.

The order of the development of more remote frontier or offshore natural gas reserves will likely be tied to crude oil development in each area. Crude oil development in the Mackenzie Delta — Beaufort Sea and the East Coast offshore will likely commence prior to the year 2000. Natural gas could be available from these areas if the United States market demand is sufficient to justify development of these reserves.

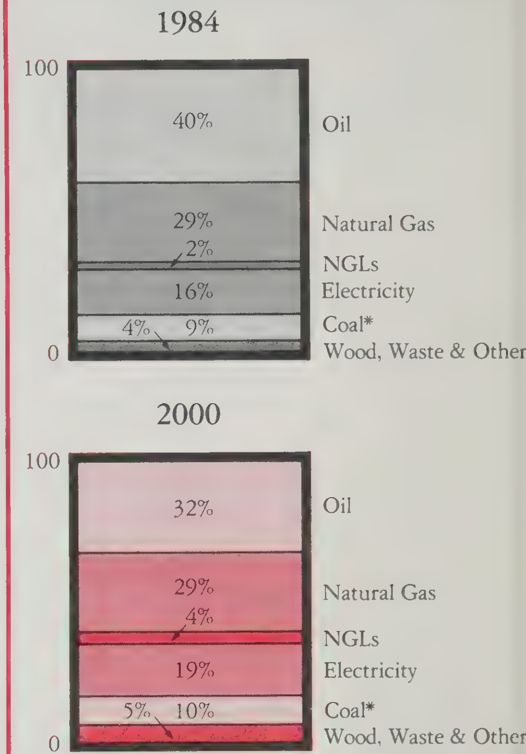
The challenge facing the natural gas industry and policy planners over the next fifteen years will be caused by pressures to move towards a deregulated natural gas market.

For Ontario, the challenge will be to obtain the lowest possible prices for natural gas in a market-sensitive environment, while maintaining as much security of long-term supply sources as possible.

Other Energy Sources

With forecasts of little escalation in Ontario's energy prices before the year 2000, and with the perception that there is little threat of an energy shortage, the prospect is for relatively slow growth in the use of new energy sources. Although the value of conventional energy supplies displaced by wood and municipal solid waste will exceed several hundred million dollars per annum, these sources will only provide approximately 4 per cent of Ontario's energy supplies. Smaller market niches will continue to exist for many other technologies and these will continue to provide industrial opportunities for Ontario as well as a useful means of gaining experience with these technologies.

Energy Fuel Shares



* Excludes coal used by electric utilities.

Energy demand is expected to grow by 18% over the period 1984-2000. The balance in the mix of energy sources will continue to improve with reduced dependence on oil.

Coal is expected to continue to play an important role as feedstock and an energy source in the steel industry. It could also still be used to provide fuel diversity in the electricity supply sector.

Alternative transportation fuels could supply between one and two per cent of total end-use energy in the year 2000.

The challenge for both government and the private sector will be to maintain an appropriate mix of research and development, demonstration, and commercialization activities for new technologies that may make a larger contribution to Ontario's energy supplies beyond 2000.

APPENDICES

APPENDICES

Appendix A: Alternative Electricity Generation Technologies

Alternative generation in Ontario is defined in this paper as electrical generation within the Province done by someone other than Ontario Hydro, as well as non-conventional generation even if done by Ontario Hydro. Though a variety of technologies can be used for alternative generation, three which have excited considerable public interest are: small hydro, wind turbines, and photovoltaics.

Small Hydro

A dam is usually needed to divert and store the water and a pipeline or penstock is needed to carry the water to the turbine. Inside the turbine a runner turns with the force of the passing water. The turbine then drives a generator which produces electricity.

Several options are available for small hydro layouts and equipment. Old hydro sites, which once produced mechanical power, can be modified to accept a hydroelectric unit. In this case, equipment is built to fit the existing structure or the old turbine is used to drive a generator.

Sites with a dam but without existing facilities can be developed by connecting a turbine to a siphon penstock over the dam; by utilizing an existing pipe through the dam; or, by putting a new penstock through the dam. A range of turbine types is available. Most sites in Ontario have a head of less than 20 metres, and so are considered low head. Turbine types suitable for low head sites include the propeller, Kaplan (adjustable propeller) and Francis.

Potential developers of small hydro include municipal utilities, who can sell the power to their customers; industries, who can offset power purchases; and entrepreneurs, who can sell power to Ontario Hydro.

Wind Power

Windmills convert the kinetic energy of the wind into an energy form which society can more easily use. In the past, windmills have been used to produce mechanical energy for pumping water and for grinding corn. More recently, windmills have been developed to generate electricity. There is currently little doubt that electricity-generating windmills can be built since such machines have been in use for decades. There is, however, uncertainty as to their economics and their environmental acceptability.

Modern wind turbines have been commercialized in a number of areas. Substantial tax incentives, good wind regimes and the high costs of conventional energy sources have led to a substantial windpower industry in California. Over 6,000 machines totaling more than 500 megawatts have been installed in the United States. Several thousand machines are in operation in Europe.

While the development of large machines (windmills with blades up to 90 metres in diameter) has been slowed, they have been shown to be technically feasible and potentially economic in good wind regimes. Medium size machines are being used successfully in remote areas with high energy costs. As machine designs improve, costs are likely to fall and machines will become more widely economic.

Photovoltaics

Photovoltaics involves the use of a semiconductor, usually silicon, which frees electrons when exposed to direct sunlight. The front surface of a solar or photovoltaic cell is specially treated so that the freed electrons migrate to this surface. The resulting imbalance between the negatively charged front and positively charged back surfaces of the solar cell creates a flow of electricity when the two surfaces are joined by a conductor.

The technology was first developed in the 1960s and used as a source of power for satellites. Expensive solar cells designed for use in the space program were made of single crystal silicon. Today, less efficient but less expensive photovoltaic cells are being developed for running water pumps, communications facilities and small communities.

The advantages of photovoltaics include ease of use in remote areas, small cell size, extremely high reliability over long periods and zero fuel costs. The cost of solar cells is falling. Photovoltaics are becoming a competitive source of electricity in areas that would normally depend on diesel generators. Large grid-connected photovoltaic arrays have been built in Japan and California but they are not yet economic for widespread application.

Appendix B: Heavy Crude Oil Upgrading and Integrated Oil Sands Plants

Heavy Crude Oil Upgrading

Canada has large deposits of heavy crude oil. When processed in a typical Canadian refinery, heavy crude oils yield large volumes of asphalt and/or heavy fuel oil, products with only limited demand in Canada. The value of these heavy crude oils can only be fully realized if they can be "processed" or "upgraded" to a more usable form such as synthetic light crude.

Crude oil is made of a complex mixture of hydrogen and carbon molecules. Heavy crude oil has a much higher carbon content than light crude oil which has a much higher hydrogen content. Upgrading the heavy crude oil involves two processes — "coking" and "hydro-cracking". The coking process removes carbon from the crude oil (in the form of petroleum coke) while the hydro-cracking process adds hydrogen.

Upgrading heavy crude oil will eventually produce higher value products such as gasoline, and in a very real sense make a substantial contribution to Canada's crude oil supplies.

What Is an Integrated Oil Sands Plant?

Unlike most other mineral industries, at an integrated oil sands plant all three phases of production — mining, extraction and upgrading — are performed simultaneously at a single facility. This close integration requires that all of the unit's operations be compatible with all other functions in the integrated system. In Canada, there are two such facilities, operated by Suncor Inc. and Syncrude Ltd., creating synthetic crude oil from the Athabasca Oil Sands.

Mining

Oil sands typically consist of a sand or sandstone matrix (ore) impregnated with a heavy viscous asphaltic bitumen. Mining of the oil sands to recover the bitumen requires that the below-ground ore be excavated and brought to the surface where it is treated, the bitumen extracted and the waste sand disposed of in an environmentally acceptable manner.

Extraction

Once the oil sands are mined, the bitumen must be separated from the sand matrix. This extraction step is one of the most critical and complex operations in the overall recovery process. It generally involves treating the ore with hot water and a solvent to separate the sand and bitumen. The bitumen product is black, very viscous and perhaps combined with

some light hydrocarbon solvent, water and/or mineral matter. These physical and chemical properties of bitumen make upgrading necessary to convert the material into a more usable product.

Upgrading

Bitumen derived from oil sands is generally hydrogen-deficient compared to most conventional crude oils. During the upgrading it is necessary to increase the hydrogen-to-carbon ratio of the bitumen material. This is done either by reducing the carbon content through a coking process, increasing the amount of hydrogen through a hydrogenation process or by a combination of the two. Both the Suncor and the Syncrude facilities employ the simpler coking process to produce a synthetic crude oil suitable for pipelining and processing in a conventional refinery. This is then used to produce a number of transportation and heating fuels.

For the integrated oil sands plants, the simultaneous performance of each of these phases is necessary to maintain maximum operating efficiency. With current technology, steady-state output in the mining phase of oil sands operations is the most difficult to maintain. Despite this, the Suncor and Syncrude operations are together able to mine roughly 350,000 tonnes of sand per day, yielding 175,000 barrels (1.1 petajoules) of synthetic crude oil daily.

Appendix C: Petroleum Refining

A refinery is the most important middle-link that transforms crude oil into the many different petroleum products that our lifestyle demands. When the crude oil reaches the refinery, it is processed through three stages: Separation — Conversion — Product Blending.

Separation

During the separation stage, the crude oil is processed by "Atmospheric Crude Distillation" to separate it into four main products or fractions: gases, light distillates, middle distillates and residual products. The separation of these fractions occurs by heating the crude oil to temperatures that cause it to vapourize. As the vapours rise in a distillation tower, they cool and condense. The four fractions have differing chemical compositions causing them to cool and condense at different levels in the tower, thus enabling the recovery of separate product streams.

Gases are the most volatile fraction. They are removed at the top of the distillation tower. Methane, ethane, propane and butane are the major components of these gases.

Light distillates condense at slightly lower temperatures and are recovered as automotive and aviation gasoline and naphtha.

Further down the distillation tower **middle distillates** such as kerosene, diesel fuel, jet fuel and furnace oil are recovered.

Residual products are much like the leftovers of the refining process and include gas oils, heavy fuel oil and asphalt.

Some refineries further separate the heavier products by distilling them under a vacuum. This allows the oil to be vapourized at lower temperatures than would be the case in the "atmospheric" tower.

Conversion

Once separated, some of the crude oil components are further processed by **catalytic cracking**, **reforming** or **alkylation**. Some of the residual gas oils, for example, are converted to gasoline blending stocks using the **cracking** process in which a **catalyst** is used to accelerate the chemical conversion process that occurs. **Reforming** is another common conversion process from which high grade gasolines are produced by heating a stream of light distillate naphtha into a high octane gasoline blending stock. **Alkylation** is also used to produce gasoline by converting light fractions released during the reforming and cracking processes.

Product Blending

Once the crude oil fractions have been separated and converted, they are blended together to create a wide range of consumer products. For example, various **grades** of gasoline are produced to meet certain octane levels. Different gasoline stocks with varying octane levels are mixed together to produce regular, lead-free and premium gasoline blends.

In 1984, Ontario refineries produced approximately 170 million barrels of the following refined petroleum products:

Products	**barrels (millions)**
Gases, LPG	4.6
Petrochemical Feedstocks	17.9
Gasoline	74.4
Aviation Turbo Fuel	8.1
Kerosene and Stove Oil	0.8
Diesel Fuel	24.0
Light Fuel Oil	16.1
Heavy Fuel Oil	8.0
Lubricants	2.7
Asphalt and Coke	5.4
Other Products	8.0
Total	**170.0**

Source: Statistics Canada Catalogue No. 45-004, Refined Petroleum Products, volume 39, number 12, December 1984.

Appendix D: Principles of Fusion

Nuclear fusion is the transformation of matter into energy by the collision of atoms. When two atoms collide at high speeds, they may join together to form a completely different atom. The mass of the newly formed nucleus is less than the original nuclei due to the conversion of part of the mass into energy as a result of fusion. To allow fusion to take place, the collision speeds of nuclei must overcome the tendency of positively charged atoms to repel each other. High pressures and temperatures can create such speeds to efficiently join light-weight elements.

Fusion in the sun involves the collision of hydrogen atoms. Hydrogen is the lightest and most abundant element in the universe. The gravitational field of the sun leads to high densities and therefore a high rate of collision. A fraction of the energy from fusion in the sun travels out to space, sustaining all life on earth.

Two routes are currently being pursued in trying to harness fusion for controlled energy conversion. The first — magnetic confinement — involves heating gases to very high temperatures and containing them with magnetic fields. The second — inertial confinement — uses lasers or other means of delivering large amounts of energy very quickly to fuel particles and making use of the inertia of the particles themselves to keep them together long enough for fusion to occur.

Appendix E: Units Used in the Paper

Energy Units

It is common in the energy industry to refer to reserves by volume — barrels in the oil industry, and thousands of cubic feet (Mcf) in the natural gas industry. Energy measures are also used: kilowatt hours (kWh) in the electricity industry and megajoules (MJ), gigajoules (GJ), and petajoules (PJ). Throughout the paper, the industry standard unit is used, followed in brackets by the metric energy measure (based on accepted conversion factors calculated using average conditions for oil and natural gas supplies).

Comparisons can thus be made within sections, across sections and also with the companion paper, **The Shape of Ontario's Energy Demand.**

Conversion factors used are as follows:

Electricity	278 kWh per GJ	or 0.0036	GJ per kWh
Crude Oil	0.163 barrel per GJ	or 6.1	GJ per barrel
Natural Gas	0.932 Mcf per GJ	or 1.07	GJ per Mcf

Prefixes used are as follows:

• kilo	10^3	thousand	• tera	10^{12}	trillion
• mega	10^6	million	• peta	10^{15}	
• giga	10^9	billion	• exa	10^{18}	

One joule is a very small amount of energy. It is approximately equal to the energy given off when a 60 watt light bulb is used for one sixtieth of a second.

A gigajoule is one billion joules. An average house in southern Ontario needs about 100 GJ per year for heating.

A petajoule is a million gigajoules. Ontario, as a province, used about 2,400 PJ of end use energy in 1984.

An exajoule is a thousand petajoules. Canada annually exports approximately one exajoule of natural gas to the United States. The world's known conventional oil reserves are estimated to be several thousand exajoules.

Costs

Costs can be referred to in a variety of ways. Because of inflation — general price rises across the economy — prices can be referred to either in real terms (constant dollars tied to a particular year), or in current or "as spent" dollars. The latter reflect the reduced purchasing power caused by inflation of money spent at a future date. In this paper all costs are in constant 1985 dollars except where otherwise noted.

Copies of this and the companion publication
The Shape Of Ontario's Energy Demand
are available free of charge from the Ontario Government Bookstore, 880 Bay St., Toronto. Out-of-town customers write to Publications Services Section, 5th Floor, 880 Bay St., Toronto, Ontario M7A 1N8. Tel. 965-6015. Toll Free long distance 1-800-268-7540; in Northwestern Ontario 0-Zenith 67200. A charge may apply to bulk orders.

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